

## Pipelines & Utilities

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## Ontario Electricity Market

The Future Is Bright

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*All figures in Canadian dollars, unless otherwise stated.*



- The Ontario government's announcement that it intends to privatize Hydro One signalled its commitment to complete the restructuring of the Ontario electricity industry — a signal confirmed by the subsequent announcement that the market will open to competition on May 1, 2002. We view these developments as positive for consumers, the Ontario economy, and investors alike. We find the commitment to proceed with deregulation as especially positive for investor-owned companies such as TransAlta, TransCanada PipeLines, ATCO Power, Fortis, and Enbridge.
- In this report we review the basic structure of the new Ontario electricity market and we provide a brief overview of the major players. As well, we examine some of the key success factors of deregulation and the possible impacts on electricity supply and demand, as well as the resultant opportunities created for companies. Finally, we examine and hopefully debunk some of the common myths that have been circulating since the privatization announcement. This report is a follow-up to our report entitled *Canadian Electricity Deregulation* dated January 31, 2001.

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## Executive Summary

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The recent announcement by the Ontario Government setting the date of Open Access (May 1, 2002) to the Ontario Electricity Market was the culmination of a long and intense deliberation and consultation with all stakeholders. In the end, the compelling economics, anticipated public policy benefits, and forces for change sweeping interconnected and global electricity markets provided the impetus to adopt a competitive model for Ontario's electricity market.

On April 1, 1999, Ontario Hydro was split up into five successor companies. Hydro One, which inherited Ontario Hydro's transmission and distribution business, will soon be privatized, and we expect Ontario Power Generation (OPG), which inherited Ontario Hydro's generation business, to be privatized in the next 18 to 36 months. The other three entities provide vital support functions for the market and will remain owned by the Government. Local distribution utilities were also required to incorporate.

Market rules have been established to ensure that no one entity will wield undue influence in the competitive power and energy markets. As a result of these rules, OPG is slated to decontrol a substantial proportion of its generating assets so that its market share of capacity comes down to 35% within 10 years after Open Access commences. Transmission and distribution systems as currently designed are monopolistic, and therefore, will remain subject to regulation. That said, incentive regulation is being introduced to encourage these companies to operate as efficiently as possible.

Following Open Access, customers will be able to choose from whom they buy their electricity; however, it is likely that many retail consumers may not choose to buy electricity from a competitive retailer — either due to apathy or discomfort with change. These customers will have a default supply option (standard supply service = SSS), which will be supplied by their existing distributor at an average spot market price. Regardless of whether they choose competitive or standard service, approximately 40% of their total electricity bill will remain regulated in the form of transmission and distribution charges.

Approximately 143 TWh of electricity was consumed in Ontario in 2000. Demand has grown at an annual rate of 1.6% since 1994, and we estimate that demand will grow by approximately 1.1% annually over the next 10 years. Growth in demand is largely a function of growth in the overall economy, although trends such as decreased demand due to energy conservation, or conversely increased demand due to the use of air conditioning, also influence overall demand. Our forecasts suggest that Ontario will have ample supply (in the form of generation and transmission) to meet and exceed this demand. This ample supply implies an opportunity for generators to export power to the U.S. Northeast and Midwest, where the existing generation mix tends to be higher cost than Ontario, with its relatively high proportions of low-cost nuclear and hydroelectric power. The province is also interconnected with Manitoba and Quebec, although the ample supply of hydroelectric power in these provinces suggests that Ontario will be a net importer of their power.

Our research leads us to believe that the Ontario Electricity Market has all the key ingredients for a smoothly functioning market — especially adequate supply and a robust market design. Market prices provide signals to support efficient decision making by all parties, and opportunities abound for both established incumbents and entrants alike.

OPG and Hydro One will likely grow beyond the borders of Ontario and export their expertise in generation, transmission, and distribution in adjacent markets. Of course, such expansion must not distract the companies from improving operations in their home market. Given that many American power generation companies have scaled back growth prospects, we anticipate substantial opportunity for home-grown talent to shine in the near term. Managing costs and developing a competitive mindset at all levels of the organization will be key challenges for the companies.

Entrants into Ontario will likely be opportunistic as they seek toeholds that will enable them to leverage their unique strengths. **British Energy**, through its subsidiary Bruce Power, has leased and is operating the Bruce nuclear generating plants — the first of many to be decontrolled by OPG. **TransAlta** will now be able to sell surplus power from its plants in Sarnia and Windsor. **TransCanada PipeLines** will be able to pursue additional gas-fired generation projects along its pipeline and will likely extend its wholesale marketing activities to Ontario. **ATCO Power** has already proposed a new generation facility near Windsor. **Fortis** may be able to enlarge its existing distribution presence in Ontario and/or develop small hydroelectric facilities. **Enbridge** should be able to leverage its Energy Services and Consumers Gas operations to realize economies of scope in combining gas and electric retailing operations, and also gas and electric distribution operations. While lacking a large local presence initially, new entrants can use this to their advantage by nimbly responding to market dynamics. Over time, the lines will blur between the incumbents and the entrants, and the markets will mature into a vibrant commerce hub. The future of the Ontario Electricity industry, and the companies that can create and capture value in the Market, is certainly bright.

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## Restructuring For Competition

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### December 2001 Announcements Confirm Commitment To Restructuring

On December 12, 2001, Ontario Premier Mike Harris announced that the government will privatize Hydro One through an initial public offering (IPO). We expect the IPO to be completed in Q2/2002, and to likely be the largest IPO in Canadian history. With the take-over of Westcoast Energy by Duke Energy, we expect Hydro One will rank as the third-largest market-capitalization pipeline or utility stock in Canada. Shortly afterwards, on December 18, 2001, the premier confirmed that the province's electricity industry will open to competition on May 1, 2002.

Privatization is related to, but distinct from the central feature of restructuring, namely the deregulation of the *generation and sale* of electricity. The *delivery* of electricity, which represents the vast bulk of Hydro One's business, will remain regulated by the Ontario Energy Board (OEB). The benefits of deregulation are the positive long-term impacts on electricity supply and prices, as producers (either within or beyond Ontario) compete with each other to serve the market. We also anticipate that customers will benefit from a greater range of choice, including the ability to hedge future prices or to select the most environmentally benign sources of power.

The primary benefit of privatization that we anticipate is increased efficiency or cost-effectiveness generated by the discipline of the financial markets. As well, it is arguable that privatization of Hydro One could forestall any trade argument by U.S. power suppliers that Ontario-based exporters are being unfairly subsidized with lower transmission rates as a result of the lower cost of capital available to a government-owned or not-for-profit corporation.

These announcements are the culmination of many years of deliberation and consultation with many stakeholders. The momentum for deregulation began in earnest earlier with the passing of the Energy Competition Act.

### The Electricity Act – A Part Of The Energy Competition Act

In 1998, after several years of study and following the lead of other jurisdictions in North America and globally, Ontario passed the Energy Competition Act. The Act fundamentally restructured the electricity industry, providing for an end to the monopoly generation and sale of electricity. In the monopoly era, Ontario Hydro and municipal distribution utilities sold electricity to customers within specific geographic areas at prices that were based on the average cost of generating and delivering power. The Electricity Act provided for a transition to competitive wholesale and retail markets.

The transition will be complete when open access is implemented on May 1, 2002. On that date, generators and marketers of electricity (either within or beyond the borders of Ontario) will be able to sell electricity directly to wholesale or retail customers at prices determined by market forces. The wires, over which the electricity moves, will remain regulated but will be open to all industry players on a nondiscriminatory or open-access basis.

## The Break-Up Of Ontario Hydro

Prior to April 1, 1999, Ontario Hydro supplied substantially all of Ontario's electricity needs. It sold electrical power directly to large industrial customers, to municipal distribution utilities such as Toronto Hydro, and directly to rural retail and commercial customers. Pursuant to the Power Corporation Act, rates were set by Ontario Hydro's own board of directors, subject only to the requirement to comply with policy statements and directives from the province and to consider recommendations from the OEB.

Effective April 1, 1999, Ontario Hydro was split into five successor entities. Ontario Power Generation (OPG) inherited Ontario Hydro's generation function, while Hydro One assumed Ontario Hydro's transmission and distribution function. The Independent Electricity Market Operator (IMO) became the successor to Ontario Hydro's central market operations division, while the Electrical Safety Authority assumed the electric installation inspection function previously conducted by Ontario Hydro. The Ontario Electricity Financial Corporation (OEFC), as the continued Ontario Hydro, is responsible for managing and retiring Ontario Hydro's outstanding indebtedness and remaining liabilities (including stranded debt). More details on most of these corporations are provided in the following section.

Each of Ontario Power Generation and Hydro One was established with capital structures appropriate for their respective industries (competitive generation and regulated transmission/distribution). Initially, the debt of these two companies was held by the OEFC, but will be retired or redeemed as the two companies issue public debt in their own name.

The original debt and other liabilities of Ontario Hydro over and above the aggregate debt of the successor corporations were labelled as stranded debt. Amounting to approximately \$21 billion at the time, the stranded debt will be primarily repaid or defeased with the proceeds of taxes or payment in lieu of taxes payable to the provincial government by OPG, Hydro One, and the municipal distribution utilities. As well, as long as OPG and Hydro One are owned by the province, their common share dividends will also be used to service and retire OEFC and stranded debt, as will the net gain from Hydro One's privatization. To the extent that these payments are insufficient to retire the stranded debt, an additional per-kilowatt-hour (kWh) debt retirement charge will be levied on all electricity consumed in the province. The stranded debt charge is currently set at 0.7 cents per kWh, and is subject to change by the Minister of Finance.

## Changes Also Affect Municipal Distributors

The Electricity Act also changed the way in which Ontario's municipal distribution utilities (or local distribution companies, LDCs) conducted their business. They were required to incorporate under the Ontario Business Corporation Act and to incorporate their monopoly distribution (wires) business separately from their competitive businesses. Like Hydro One, beginning May 1, 2002, they will be required to offer nondiscriminatory access to their wires to all market players at rates regulated by the OEB. Exempt from federal and provincial income tax, they will nonetheless make payments in lieu of taxes to the provincial government to help pay down Ontario Hydro's stranded debt.

If a municipality elects to sell its distribution business, it must pay a 33% transfer tax on the gross sale value, the proceeds of which will be used to help retire stranded debt. As acquirers, Hydro One and municipalities were exempt from this transfer tax through November 7, 2000, although this exemption subsequently disappeared. Hydro One has acquired 88 LDCs, and this transfer-tax exemption was a large driver of its competitive advantage in the bid process. Despite the transfer tax, however, we expect further

consolidation of the distributors over time following market opening as the transfer tax dissipates. We note that Hydro One's relative size advantage, and the scale economies it will enjoy, still positions it well in a bidding process.

LDCs were required to submit self-certification documentation to indicate readiness for market opening. As of December 17, 2001, 89 of the 94 LDCs had filed, and the OEB anticipated that 51 LDCs would be ready for market opening, representing about 82% of Ontario customers.

## **Curtailing Market Power**

In order for a competitive market to function properly, no single participant should be able to exercise market power. Given OPG's dominant starting position (see the description of OPG below) it will be subject to a market-power mitigation agreement. Within 42 months of Open Access (May 1, 2002), OPG is required to relinquish control of the greater of either 4,000 megawatts (MW) of "Tier 2" generating capacity or enough of its generating output so that its share of the Tier 2 market does not exceed 35%. Tier 2 is defined as all non-nuclear or non-hydroelectric generating capacity, which, by virtue of its higher marginal costs, is likely to be price-setting. OPG can relinquish control of Tier 2 capacity through a sale, long-term lease, or some other means. It may substitute up to 1,000 MW of hydroelectric capacity for an equal amount of fossil capacity. Within 10 years of open access, OPG must reduce its overall generating market share to no more than 35%.

As a further market-power mitigation measure, for the first four years of Open Access, OPG will be subject to an average annual price cap of 3.8 cents per kWh on 90% (initially) of its calculated expected sales in the spot energy market. OPG is free to bid in the spot market, but if at the end of the year, OPG's average revenue in the spot markets has exceeded this amount, OPG must refund the difference to consumers through the IMO. The amount of generation subject to this price cap will fall over time with the decrease in OPG's market share, by a factor of 110%.

## **Standard Supply**

Following open access on May 1, 2002, all customers will be able to choose the supplier from whom they will buy their electricity. Some of the municipal electric distribution utilities such as Toronto Hydro have set up separate nonregulated subsidiaries, which will buy and sell electricity on a for-profit basis. As well, several independent marketing firms such as Direct Energy and Energy Savings Corporation will add electricity to their sales portfolio. We also expect Enbridge Home Services, which began selling natural gas in 2001, to sell electricity as well. Established distributors from other regions are expected to infiltrate the market, and we anticipate that EPCOR, headquartered in Edmonton, Alberta, will become active in the market as a result of its purchase of Union Energy from Westcoast. Customers that do not choose to buy their electricity from a competitive supplier will receive standard supply services (SSS) from their current distributor. Under the standard supply option, customers will pay the average spot market cost incurred by the distributor to supply electricity. The distributor will make no profit on standard supply.

## The Interim Period

During the interim period — defined as the time between the break-up of Ontario Hydro on April 1, 1999, and the introduction of open access on May 1, 2002 — rates to end use customers have remained bundled. OPG is giving Ontario customers (municipal, direct industrial and individual) priority access to its output and, where necessary, buys additional power to meet customer needs. As well, OPG's wholesale rates have remained frozen at the levels set prior to the reorganization.<sup>1</sup>

During the transition period, OPG's wholesale revenues are shared between the Ontario Hydro successor companies according to a Revenue Allocation Agreement. The IMO and OEFC receive a fixed fee, while Hydro One is paid its OEB-approved transmission revenue requirement. OPG retains the residual revenue, which leaves it at risk for variations in sales volumes and mix.

The transition period will end on May 1, 2002, when open access is implemented, electricity bills will be unbundled, the price of electricity will be allowed to fluctuate (subject to constraints imposed on OPG by the Market Mitigation Agreement discussed above), and customers will be allowed to select their provider of electricity.

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<sup>1</sup> On March 30, 2001, the province issued a regulation under the Electricity Act, 1998, enabling OPG to increase the wholesale cost of power by 0.7 cents per kWh on all energy charges effective June 1, 2001. Hydro One passed this increase on to its customers.

## The Incumbents

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### The Orchestrator: Independent Electricity Market Operator (IMO)

The IMO controls the safe and reliable operation of the bulk electrical power system in Ontario, which involves balancing the demand and supply of electricity in real-time to ensure uninterrupted supply of energy to consumers. The IMO is also championing the drive to a competitive, deregulated electricity marketplace in Ontario, under the direction of the Ontario Ministry of Energy, Science and Technology. After May 1, 2002, it will run the wholesale electricity markets and bill and settle financial accounts with market participants. The IMO is a nonprofit, regulated corporation that is independent of all other players in the industry and manages the interests of all stakeholders.

### The Generator: Ontario Power Generation (OPG)

#### Strategy

OPG is the successor to Ontario Hydro that assumed the latter's generation assets. Its corporate strategy is as follows:

1. Improve generation operations and increase cost competitiveness;
2. Develop marketing and sales as well as new products and services;
3. Extend market reach and optimize the asset portfolio; and
4. Pursue energy technology investments to defend against and grow with major industry changes over time.

#### Operations

Currently OPG accounts for the bulk of generation in Ontario, but this will change as the market mitigation requirements are executed. In 2000, the company provided 89% of the province's energy requirements, and the company's energy balance is shown in Table 1.<sup>2</sup>

**Table 1. OPG's Energy Balance In 2000 (TWh)**

Generation	136.2
Import	3.3
Received	0.3
Export	(4.0)
<b>OPG For Ontario</b>	<b>135.8</b>

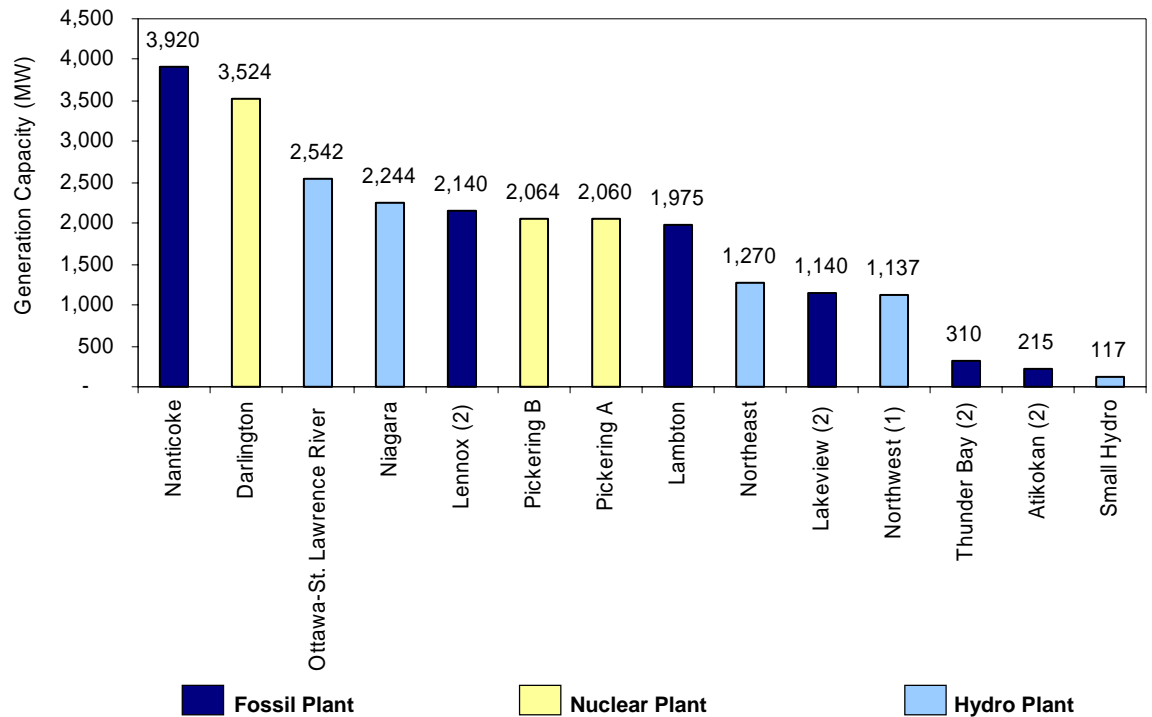
Source: OPG.

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<sup>2</sup> Energy requirements defined as including systems losses and including behind-the-fence generation.

The company’s generating assets reside entirely in Ontario and consist of 68 hydroelectric, six fossil, and three nuclear stations with a combined capacity of 24,658 MW. This count includes the laid-up Pickering A nuclear station whose 2,060 MW will be returned to service over the next two years, but does not include the Bruce A and Bruce B nuclear stations, which have been leased to Bruce Power. With respect to operating in a competitive electricity market, and especially after the decontrol discussed below is achieved, OPG is likely to be well positioned to have an operating cost advantage due to its substantial base load generators and disproportionate share of nuclear and hydroelectric generating units.

Figure 1. OPG Generating Stations



<sup>1</sup> Four stations targeted for decontrol (488 MW).  
<sup>2</sup> Stations targeted for decontrol.  
 Source: Company.

OPG has already made substantial progress in its endeavour to find lessors and/or buyers for those units targeted for decontrol. The Bruce A (3,075-MW capacity) and Bruce B (3,140-MW capacity) stations are being leased and operated by Bruce Power, (approximately 85% owned by British Energy), until 2018, with an opportunity to extend the lease for up to a further 25 years. The four Bruce A units are currently laid up, but Bruce Power intends to get two of them, with a combined capacity of 1,538 MW, up and running by 2003. We have heard third parties state that a third unit could be brought into service, but the fourth unit is likely to remain laid up. The total value of the transaction is more than \$3.2 billion, and we view this as a vote of confidence by a seasoned international generator (British Energy) on the viability of the Ontario Electricity Market.

Pursuant to the Market Power Mitigation Agreement (discussed above), and now that the Ministry of the Environment (MOE) has lifted its moratorium on the sale of coal-fired plants in the province, OPG is in the process of achieving decontrol of its Lennox, Lakeview, Thunder Bay, and Atikokan, as well as the Mississagi River hydro stations. In addition to the Bruce nuclear units, these units represent a further 4,293 MW, or 17%, of capacity slated for decontrol, and the units are identified in Figure 1. This decontrol will be partly offset by the return to service of the Pickering A units, which in total represent 2,060 MW. Currently, the

company plans to bring the Pickering units back into service between 2002 and 2003. We anticipate that all four units will be in service by the end of 2003.

New emissions regulations are designed to reduce smog causing nitrogen oxides (NOx) by 53% and sulphur dioxides (SOx) by 25 % by the year 2007. This will impact the company's operations, in that emission controls will be managed more closely. Lakeview will cease burning coal by Q2/2005. An emissions trading system introduced will enable OPG (and future owners) to reduce emissions without necessarily reducing output in its fossil generating units. We note that potential purchasers of generating units slated for decontrol will likely factor in these incremental emission-reduction costs into the asset prices.

In 1997, the company embarked on a comprehensive, \$1.4-billion, seven-year nuclear recovery plan to improve the operating performance of its nuclear units. By year-end 2000, the company had spent \$850 million of the budgeted amount. The company is striving to meet and exceed performance targets and benchmarks based on global standards by standardizing its operations and implementing initiatives to improve: accountability; management and operational control systems; maintenance and inspection programs; regulatory compliance; performance standards; and employee training.

The financial risks of third-party liability are somewhat limited, as the Nuclear Liability Act of Canada currently caps this at \$75 million. That said, the number could increase in the future. Disposal of nuclear waste is a very important element of nuclear operations, as handling waste could expose the company to third-party liability. As well, good corporate citizenship suggests that the total societal impact should be paramount when managing nuclear operations. The most radioactive type of waste are the spent fuel rods themselves, and after they are removed from the reactors, they are placed in "wet bays", specially designed pools of water, for a cooling-off period of 10 years, over which time their radioactivity substantially decays. After this cool-off period, they are transferred to above ground, on-site "dry storage". Plans have been made for a deep geological disposal facility to be available between 2025 to 2035, and although it is technically very sound, the plan lacks widespread public support.

Material that has come in close contact with the reactors, but is less radioactive than fuel, is classified as intermediate-level radioactive, and must also be disposed of effectively. Once the useful life of a nuclear plant has passed, the cost to decommission it is quite substantial. The plant must be defuelled, after which it rests and is monitored for a 30-year period. The subsequent dismantling process itself is expected to take 10 years.

The province is sharing the liability of this nuclear waste management and decommissioning by assuming responsibility for activities prior to April 1, 1999 (when Ontario Hydro was split into its components). OPG bears the burden for activities after April 1, 1999. The company must deposit money into a trust fund to prepare for eventual decommissioning, and Table 2 shows the present value of the estimated costs.

**Table 2. Estimated Present Value of Nuclear Waste Management And Decommissioning Costs**

(\$ mlns.)	December 31, 2000
<b>Incurred Liability</b>	
Decommissioning	\$ 2,417
Waste Management	4,561
	<hr/>
	6,978
Future Liability <sup>1</sup>	434
	<hr/>
Total Liability	\$7,412
Less: Nuclear Liability Agreement Allocations To The OEFC <sup>2</sup>	2,622
Less: OPG Segregated Fund	781
	<hr/>
<b>Net Unfunded Liability</b>	<b>\$4,009</b>

<sup>1</sup> Estimated based on waste created at Pickering, Bruce, and Darlington stations during their remaining planned operating lives.

<sup>2</sup> Proposed allocation of risk-sharing between the province and OPG with respect to nuclear waste management and decommissioning.

Source: OPG.

Until market open, OPG customers will include approximately 90 municipal electric utilities, which serve approximately three million retail customers; approximately 100 large direct industrial customers and Hydro One, which serves approximately million retail customers. Through interconnections with other jurisdictions (discussed in more detail further on), OPG also sells to and buys electricity from interconnected markets in Canada and the U.S.

### Recent Results

For the nine months ended September 30, 2001, net income for the nine months dropped to \$228 million from \$543 million in 2000. The decline in earnings reflects increased activity and expense relating to the return to service of the Pickering A generating station, reduced earnings as a result of the decontrol of the Bruce nuclear generating stations, and higher pension and other post-employment benefits expense — primarily as a result of capital market conditions. As well, under the fixed price regime that is operative during the transition period prior to market opening, OPG was unable to fully recover the costs associated with higher volumes and prices of power purchased in interconnected markets.

Revenue for the first nine months of 2001 rose by 5.1% to \$4,681 million. Contributing to the increase was a 3.4% increase in energy sales to 107.3 TWhrs. Revenue per MWh sold increased slightly over this time period to \$43.63/MWh from \$42.89/MWh. Also contributing to higher revenue was an \$83 million increase in non-energy revenue — mostly the result of the lease and service revenue earned under the agreements with Bruce Power.

For the nine months ended September 30, 2001, operating, maintenance and administration (OM&A) expense rose by \$272 million (17.4%) to \$1,836. The increase was the result of higher expenditures related to the return to service of Pickering A (\$168 million); higher pension and other post-employment benefit expense (\$143 million); and inflation and other increases (\$75 million). Partly offsetting these factors was a reduction in operating costs as a result of leasing the Bruce nuclear generating stations.

Fuel expense for the nine months was \$955 million compared to \$899 million — a 6% increase. The increase reflects an increase in gas-fired generation and higher coal costs, partly offset by lower nuclear expense due to the decontrol of Bruce.

Purchased power expense jumped to \$649 million in the first nine months of 2001 from \$87 million in 2000. The major factors contributing to the increase were the agreement to purchase power from the decontrolled Bruce power plant, a decrease in hydroelectric generation due to lower water levels, environmental constraints on fossil generation and higher electricity demand during the summer season.

Property and other taxes fell by \$91 million to \$190 million in the nine months as a result of tax reform for property tax on hydroelectric facilities and a property tax refund. OPG's effective income tax rate for the nine months dropped to 33.5% from 42.7% in 2000 as a result of a drop in future income taxes resulting from a decrease in tax rates.

In terms of cash flows, OPG has ready access to cash, with recently declining cash from operations supplemented by decontrol initiatives (\$370 million from Bruce decontrol in Q2/2001) and financing through the creation of a commercial paper program (\$150 million of short-term debt was issued in Q4/2000). The company has stated its intentions to further access the capital markets in the future. Capital expenditures have been the primary use of funds, followed by contributions to the fixed asset removal and nuclear waste management provisions, which will amount to \$430 million a year between 2001 to 2004. At that time, the level of required contributions will be reassessed.

The company began paying off long-term debt to the OEFC (\$200 million in the first nine months of 2001), and endeavours to pay out 35% of earnings as regular dividends in addition to special dividends. Capital expenditures are expected to continue to increase as the company's nuclear units and emission control initiatives for its fossil units will require funds above basic sustenance of operations. The company planned for an increase in capital expenditures for continuing operations from \$585 million in 2000, to \$725 million in 2001, and \$800 million in 2002. Table 3 summarizes the company's financial statements.

#### **Nuclear Recovery Key To Success**

As demonstrated by OPG's recent financial results, the work to return the Pickering A generating station to service is having a significant impact on the company's net income. Along with the other factors described above, the restart costs contributed to a year-to-date EBIT dropped from 24% of revenues in 2000 to only 10% of revenues in 2001. The cost of the safety and environmental upgrades as well as other refurbishments required to restart the plant are estimated at \$1.5 billion — most of which OPG will expense. As of September 30, 2001, approximately \$500 million had been spent. As a result, Pickering restart costs should continue to impact OPG's bottom line through the end of 2003 when we expect the last of the four units to return to service. While we expect an improvement in margins after 2003, the performance of Pickering A, and indeed of the rest of OPG's nuclear plants, will be crucial to OPG's financial performance. We also see considerable potential as OPG diversifies into related businesses such as marketing and sales, and expands its market reach geographically.

Also, a factor for margins in 2002 will be the introduction of the rate cap (effective with market opening) of \$38/MWh on the bulk of OPG's Ontario sales. The proportion of OPG's domestic sales that will be subject to this cap will fall as it reduces its share of the Ontario market.<sup>3</sup> This gives OPG a strong incentive to proceed as quickly as possible with decontrol. We believe that this may be a challenge, as some generating companies have indicated to us that they are not interested in buying any of the OPG assets currently slated for decontrol. These units are peakers, and one company indicated that it was loath to buy peakers in a market where the largest player is government-owned. The company felt that a publicly owned company may be used a blunt instrument of social policy by the government to keep prices artificially low, which would make a peaker especially unattractive.

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<sup>3</sup> If OPG is successful in decontrolling the 4,293 MW represented by the Lakeview, Lennox, Atikonkan, Thunder Bay and Mississauga stations, the rate cap will apply to approximately two-thirds of its output.

Although the company is currently private, we anticipate that as it seeks to expand its business into new markets and new services, the Province may let it access the equity capital markets in addition to the debt capital markets. As such, we view the likelihood of a future IPO as quite high, and anticipate that it would likely come after the bulk of Pickering A's recommissioning costs have been expensed. We applaud the move, as we believe that the company's operating risk profile will change as it grows outside the Province, and therefore OPG may be less suitable as a government investment. Such a recapitalization, coupled with the upcoming competitive environment in Ontario, will have a material impact on the financial profile of the company.

Table 3. OPG Financial Statements Summary (\$ mlns.)

	Q1/00	Q2/00	Q3/00	Q4/00	Q1/01	Q2/01	Q3/01	2000	LTM
<b>Income Statement</b>									
<b>Revenues</b>	<b>1,485</b>	<b>1,399</b>	<b>1,568</b>	<b>1,526</b>	<b>1,539</b>	<b>1,507</b>	<b>1,635</b>	<b>5,978</b>	<b>6,207</b>
Operating, Maintenance & Administration	502	523	539	622	600	607	629	2,186	2,458
Fuel	302	263	334	372	315	300	340	1,271	1,327
Purchased Power	23	21	43	93	102	173	374	180	742
D&A	196	191	179	198	196	208	202	764	804
Property & Capital Taxes	94	94	93	98	69	66	55	379	288
<b>Total Operating Expenses</b>	<b>1,117</b>	<b>1,092</b>	<b>1,188</b>	<b>1,383</b>	<b>1,282</b>	<b>1,354</b>	<b>1,600</b>	<b>4,780</b>	<b>5,619</b>
Operating Income	368	307	380	143	257	153	35	1,198	588
Interest Expense	40	33	34	33	34	37	31	140	135
EBT	328	274	346	110	223	116	4	1,058	453
Income Taxes	142	115	148	48	100	74	(59)	453	163
<b>Net Income</b>	<b>186</b>	<b>159</b>	<b>198</b>	<b>62</b>	<b>123</b>	<b>42</b>	<b>63</b>	<b>605</b>	<b>290</b>
<b>Cash Flows</b>									
From Operations	738	68	213	262	83	118	(24)	1,281	439
From Investments	(106)	(128)	(138)	(532)	120	217	(191)	(904)	(386)
From Financing	(79)	(42)	(42)	108	(236)	(14)	(238)	(55)	(380)
<b>Net Cash Flows In Period</b>	<b>553</b>	<b>(102)</b>	<b>33</b>	<b>(162)</b>	<b>(33)</b>	<b>321</b>	<b>(453)</b>	<b>322</b>	<b>(327)</b>
Cash At Beginning Of Period	243	796	694	727	565	532	853	727	853
Cash At End Of Period	796	694	727	565	532	853	400	565	400
<b>Balance Sheet</b>									
Short-Term Assets	2,156	2,019	2,017	2,385	1,971	2,217	1,851	2,385	1,851
Net Fixed Assets	12,866	12,870	12,855	12,932	12,897	12,824	12,853	12,932	12,853
Other Assets	1,057	1,182	1,313	1,474	1,615	1,843	1,933	1,474	1,933
<b>Total Assets</b>	<b>16,079</b>	<b>16,071</b>	<b>16,185</b>	<b>16,791</b>	<b>16,483</b>	<b>16,884</b>	<b>16,637</b>	<b>16,791</b>	<b>16,637</b>
Current Liabilities	1,479	1,235	1,114	1,760	1,378	1,619	1,370	1,760	1,370
Long-Term Debt	3,322	3,321	3,220	3,219	3,118	3,117	3,016	3,219	3,016
Fixed Asset Removal & Nuclear Waste Management	4,300	4,364	4,425	4,482	4,550	4,608	4,668	4,482	4,668
Other Liabilities	1,454	1,510	1,629	1,513	1,583	1,658	1,776	1,513	1,776
Common Equity	5,524	5,641	5,797	5,817	5,854	5,882	5,807	5,817	5,807
<b>Total Liabilities And Shareholders' Equity</b>	<b>16,079</b>	<b>16,071</b>	<b>16,185</b>	<b>16,791</b>	<b>16,483</b>	<b>16,884</b>	<b>16,637</b>	<b>16,791</b>	<b>16,637</b>

Source: OPG.

## The TransCo and Distributor: Hydro One

### Strategy

Hydro One is poised to transform itself from a privately owned, provincial utility to an investor-owned, North American diversified electricity transportation and distribution company. The company recognizes the strength of its heritage, and its strategy focuses on leveraging existing core competencies. The main thrusts of its strategy are twofold:

#### 1. Operational Excellence

Hydro One is committed to achieving best-in-class execution and becoming the low-cost provider, recognizing the role that scale plays in this regard; and

#### 2. Related Diversification

Hydro One sees growth opportunities in expanding geographically in existing businesses, as well as diversifying into related businesses such as energy services, merchant transmission, and other related, and often unregulated, businesses.

### Transmission Operations

Hydro One owns and operates 97% of Ontario's high voltage transmission network — which is the largest component of the company's operations. Its 29,000-km grid makes it one of the largest transmission networks in North America. In 2000, the network transmitted 146.9 TWh of electricity to the company's distribution system, to 53 MEUs and also to 66 large directly connected industrial companies. The company also owns and operates the 17 interties with jurisdictions outside the province. Current operations stop at these interties, but the company has indicated its intentions to grow its footprint beyond Ontario's borders. We believe that the fragmented North American grid is ripe for consolidation, as economies of scale are considerable in the transmission business. As well, we believe that significant additional investment in the North American grid will be required to meet growth and the increased demands placed on the grid by competitive generators and marketers. Hydro One could also offer its expertise to Regional Transmission Organizations (RTOs) in the service of operating the regional transmission systems.

### Distribution Operations

Hydro One also operates the largest distribution system in Ontario, and this is the second largest component of its operations. The company transmitted 17.6 TWh of electricity to 957,000 customers in 2000. The business also serves approximately 38 large industrial customers and 124 MEUs at year-end 2000. The company operates generation and distribution systems for 20 remote northern communities isolated from the provincial grid, which will not be open to competition for the foreseeable future. Most of its 115,000-km low-voltage distribution system is rural, but in 2001, Hydro One acquired the municipal distribution system of the City of Brampton, which, with 84,000 customers, was the sixth largest MEU in Ontario and the largest to be sold in 2000. We believe that this acquisition will increase the urban distribution capabilities of Hydro One, and expect the company to leverage these new capabilities by increasing its urban footprint. Also, we believe this demonstrates the company's skill and track record in acquiring and integrating companies. To-date, it has acquired 88 municipal electric utilities, which was partly facilitated by Hydro One's exemption from the transfer tax. The company can also grow by offering network services to MEUs, likely at a lower cost than some MEUs can achieve on their own, due to the Hydro One's size and expertise.

### Other Operations

Hydro One has carved out its telecom fibre-optics cable and competitive energy services businesses, which in the past were included in the Distribution business unit. To-date, these initiatives are minor components of OPG's overall operations. Going forward, we see high growth potential for energy services as commercial and retail energy sales become open to competition. Not only will customers purchase energy, but some will also seek consultation and pay for risk management services as increasing choice leads to increased complexity.

### Financials

The bulk of Hydro One's income is regulated by the OEB via a traditional cost-of-service framework. In 2000, the transmission operations had an approved rate of return of 9.88%, based on a deemed average equity component of \$2.1 billion. Hydro One's distribution operations will be operating under a first-generation performance-based regulation (PBR) framework applicable to all utilities, which contains mechanisms to address productivity, growth, transition, and extraordinary costs. The next-generation framework will incorporate earnings sharing between the company and its customers. The company is actively pursuing the implementation of a PBR framework for each of its transmission and distribution operations. At this point, Hydro One hopes to apply in 2003 for a transmission PBR regime that would be implemented in 2004.

Our past research of Canadian pipeline and utility companies indicates that PBR can easily add on average 100 bp to ROE and often contributes about 10%–15% of share value. Average allowed returns on equity have been moving downwards in the sector for some time, and although we believe that the trend will stabilize and perhaps reverse itself, these low returns have generally dampened earnings in this sector. Although Hydro One is offsetting this impact by growing its rate base through acquisitions, earnings growth in aggregate for the sector is not coming from growth in rate bases. We view incentive regulations as key to maximizing value for both a utility company and its customers through operational and capital efficiencies, and as such see PBR as driving earnings growth and returns in the sector. Please see our sector report dated January 3, 2002, for a more complete discussion on our views of and outlook for regulated returns on equity. Our report entitled *Performance-Based Regulation*, from September 2000, provides detail around which companies are best positioned to capitalize on incentive regulation.

Hydro One is working towards becoming the low-cost provider. Head count is a significant component of the company's cost, and in 2000, 1,400 (25%) of the company's employees accepted an early retirement package. Simultaneous work process redesign should further reduce operating costs going forward. Recent contract negotiations with two major unions incorporated incentive compensation, which should contribute to aligning employee and corporate goals. Although government-owned, Hydro One pays the equivalent of corporate income taxes to the OEFC, and once privatized it will pay actual taxes, both federal and provincial.

Hydro One enjoys significant cash inflows from operations, and in addition, has ample access to the debt capital markets. Its inaugural bond issue in Q2/2000 raised \$1 billion. Also, a medium-term note program with a shelf value of \$2.5 billion valid for two years was used in Q2/2001 to issue notes for par value of \$550 million. The company launched a commercial paper program in Q3/2000 that authorized the company to issue up to \$1 billion in short-term notes. The company forecast its capital expenditures to be \$1,160 million for 2001, with \$500 million allocated towards the closing of the acquisition of the 71 MEUs. At the end of 2000, the company was \$3,446 million indebted to the OEFC, with maturity dates

ranging from 2001 to 2007 and an average interest rate of 8.13%. The company can elect at any time to prepay all or part of the notes.

At September 30, 2001, Hydro One had \$10,741 million in assets financed primarily with \$4,736 million in long-term debt, \$323 million in preferred equity, and \$3,839 million in common equity. Both the common and preferred equity are held by the province.

#### **Financial Performance**

For the nine months ended September 30, 2001, the company earned net income for common shareholders of \$338 million on revenue of \$2,418 million. This compares to \$332 million of net income for common shareholders on revenue of \$2,222 million during the first nine months of 2000. For the 12 months ended September 30, 2001, net income for common was \$366 million. The most recent financial results may not be reflective of Hydro's near-term performance, however. Effective October 1, 2001, Hydro One's cost of power rose by 1.15 cents per kWh. The increase is to help pay down the stranded debt of the former Ontario Hydro, and it has the additional effect of bumping up Hydro One's power costs to the same level as the power cost paid by other large distribution companies; however, Hydro One will not flow the full increase through to its customers immediately. It proposes to increase rates in three stages. The OEB approved an increase of 0.395 cents per kWh effective October 1, 2001. Hydro One is proposing that the remaining increases be implemented in March 2002 and March 2003. For a financial summary, see Table 4.

Table 4. Hydro One Financial Statements Summary (\$ mlns.)

	Q1/00	Q2/00	Q3/00	Q4/00	Q1/01	Q2/01	Q3/01	2000	LTM
<b>Income Statement</b>									
Revenues – Transmission	322	319	307	312	304	304	330	1,260	1,250
Revenues – Distribution (including retail)	498	353	402	450	505	408	540	1,703	1,903
Revenues – Other	8	7	6	11	7	10	10	32	38
<b>Total Revenues</b>	<b>828</b>	<b>679</b>	<b>715</b>	<b>773</b>	<b>816</b>	<b>722</b>	<b>880</b>	<b>2,995</b>	<b>3,191</b>
Operating, Maintenance & Administration	204	182	184	286	171	154	204	856	815
Purchased Power	261	172	201	232	263	205	312	866	1,012
D&A	82	81	81	104	84	87	103	348	378
Total Operating Expenses	547	435	466	622	518	446	619	2,070	2,205
<b>Operating Income</b>	<b>281</b>	<b>244</b>	<b>249</b>	<b>151</b>	<b>298</b>	<b>276</b>	<b>261</b>	<b>925</b>	<b>986</b>
Financing Charges	82	84	88	86	86	86	89	340	347
EBT	199	160	161	65	212	190	172	585	639
Payments In Lieu Of Corporate Income Taxes	73	42	60	32	78	76	69	207	255
<b>Net Income</b>	<b>126</b>	<b>118</b>	<b>101</b>	<b>33</b>	<b>134</b>	<b>114</b>	<b>103</b>	<b>378</b>	<b>384</b>
Preferred Dividend	4.4	4.4	4.4	4.4	4.4	4.4	4.4	17.6	17.6
<b>Net Income For Common Equity</b>	<b>121.6</b>	<b>113.6</b>	<b>96.6</b>	<b>28.6</b>	<b>129.6</b>	<b>109.6</b>	<b>98.6</b>	<b>360.4</b>	<b>366.4</b>
<b>Cash Flows</b>									
From Operations	185	124	267	137	247	219	287	713	890
From Investments	(113)	(140)	(119)	(154)	(111)	(199)	(390)	(526)	(854)
From Financing	(171)	(48)	(451)	(9)	(90)	462	(301)	(679)	62
<b>Net Cash Flows In Period</b>	<b>(99)</b>	<b>(64)</b>	<b>(303)</b>	<b>(26)</b>	<b>46</b>	<b>482</b>	<b>(404)</b>	<b>(492)</b>	<b>98</b>
Cash At Beginning Of Period	468	369	305	2	(24)	22	504	2	504
Cash At End Of Period	369	305	2	(24)	22	504	100	(24)	100
<b>Balance Sheet</b>									
Short Term Assets	1,025	869	560	576	598	1,034	695	576	695
Net Fixed Assets	8,395	8,463	8,504	8,519	8,542	8,636	8,913	8,519	8,913
Other Assets	846	857	856	902	1,087	1,103	1,133	902	1,133
<b>Total Assets</b>	<b>10,266</b>	<b>10,189</b>	<b>9,920</b>	<b>9,997</b>	<b>10,227</b>	<b>10,773</b>	<b>10,741</b>	<b>9,997</b>	<b>10,741</b>
Current Liabilities	1,901	782	715	1,049	1,002	1,153	1,080	1,049	1,080
Long-Term Debt	3,412	4,412	4,186	3,972	3,972	4,327	4,327	3,972	4,327
Other Liabilities	974	982	985	976	1,146	1,159	1,172	976	1,172
Preferred Equity	323	323	323	323	323	323	323	323	323
Common Equity	3,656	3,690	3,711	3,677	3,784	3,811	3,839	3,677	3,839
<b>Total Liabilities And Shareholders' Equity</b>	<b>10,266</b>	<b>10,189</b>	<b>9,920</b>	<b>9,997</b>	<b>10,227</b>	<b>10,773</b>	<b>10,741</b>	<b>9,997</b>	<b>10,741</b>

Source: Hydro One.

## Dynamics Of An Effective Electricity Market

Electricity is a unique commodity in that it can not readily be stored, and therefore balancing supply and demand in real-time is critical to avoiding system failure or excessive price volatility. In a regulated environment, the key to ensuring stable electricity markets is in the ability of the regulatory bodies to orchestrate a command and control regime that focuses primarily on engineering and the physics of electrical systems. Deregulated electricity markets add another important dimension to the supply-demand balancing equation — economics — that enables all market participants to further contribute to balancing supply and demand by responding to real-time market prices. As we will describe below, market prices provide signals to both consumers and sellers of electricity that support decision-making to buy or sell products and services for both the short and long term. Effective competitive markets should have rules and a design that are clear and easy to understand. Ultimately, such a system should 1) lower the costs of maintaining reliability; 2) deploy demand and supply resources more efficiently; and 3) guide investments in demand-side, generation, and transmission resources. A well-designed market structure that is robust under even extreme situations, can create a win-win scenario for all participants.

### System Demand

In 2000, approximately 143 TWh of electricity was consumed in Ontario.<sup>4</sup> Demand for electricity has grown at an annual rate of 1.6% since 1994, which is a much slower rate than previous rates of approximately 3% in the 1980s. We believe that this deceleration of growth can largely be attributed to consumers switching to other fuel sources in light of the relative increase in electricity prices. Much of the price increase was intended to recover capital costs associated with construction of the Darlington nuclear generating station.

Commercial demand fuelled this growth as office space and multiresidential buildings increased, and both existing and new commercial customers increased use of electronic equipment and air conditioning. Industrial demand has also grown, although over half of this demand is from commodity-based industries, which have not grown apace with manufacturing industries in the past decade. Residential demand declined to hit a low in 1997, as customers replaced inefficient appliances and converted electric space and water heating units to natural gas. Since 1997, residential demand has recovered slightly as more air conditioners were installed and housing construction increased. Table 5 indicates each segment's share of consumption in 2000, and Table 6 depicts consumption within the residential and commercial sectors.

**Table 5. Market Segmentation**

Industrial	35%
Commercial	40
Residential	25
<b>Total</b>	<b>100%</b>

Source: OPG.

<sup>4</sup> Demand is based on the IMO-controlled grid, and excludes loads supplied by either embedded (behind-the-fence) generation or outside the IMO-controlled grid (e.g., Cornwall Electric).

**Table 6. Typical Share Of Energy Consumption Within Commercial And Residential Sectors**

Residential Energy Use	Residential Share (%)	Commercial Energy Use	Commercial Share (%)
Space Heating	33%	Lighting	29%
Water Heating	15	Space Heating	19
Space Cooling	10	Space Cooling	13
Refrigeration	9	Water Heating	9
Lighting	6	Office Equipment	7
Electronics	5	Ventilation	6
Cooking Products	5	Refrigeration	4
Washers / Dryers	4	Computers	2
Computers	1	Cooking	2
Other <sup>1</sup>	12	Other <sup>2</sup>	9
<b>Total Residential</b>	<b>100%</b>	<b>Total Commercial</b>	<b>100%</b>

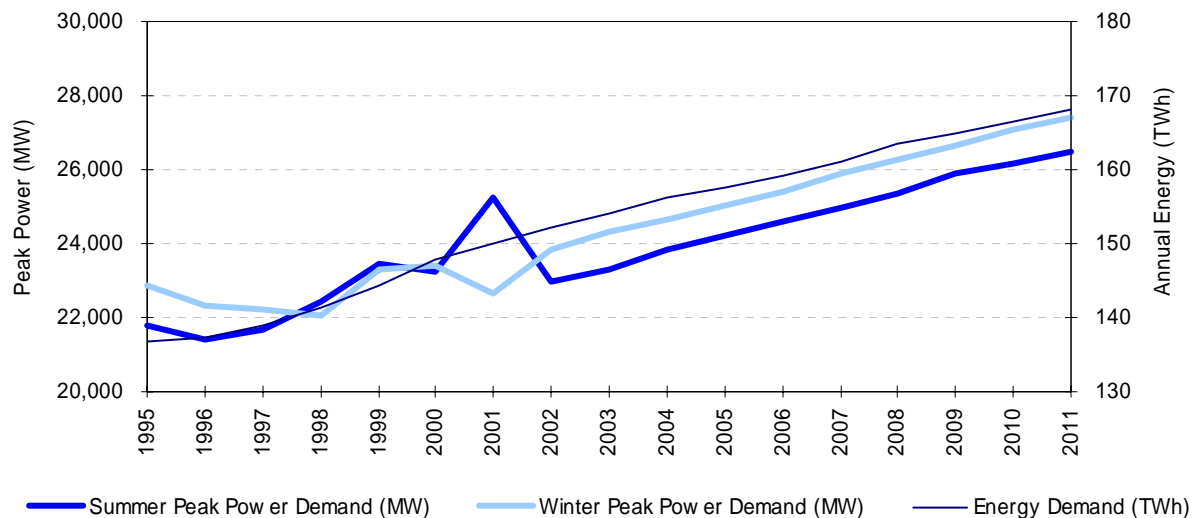
<sup>1</sup> Includes small electric devices, motors, heaters for swimming pools and hot tubs, and other uses.

<sup>2</sup> Includes service-station equipment, automated teller machines, telecommunications equipment, medical equipment, street lighting and other uses.

Source: Arthur D. Little.

Over the long term, growth in electricity demand (as measured both by energy and peak power demand) is highly correlated to broader economic conditions; however, on any given day, demand is very dependant on the calendar date and time. Weekdays tend to have higher demand than weekends, as more commercial and industrial facilities are operating. On a given day, residential demand peaks in the evening as individuals return home and conduct domestic activities, such as cooking. During the winter, when days are shorter, lighting demand increases as well, which increases the peak experienced when individuals return home in the evening. The bulk of variability across the seasons can be attributed to temperature, as extreme cold in the winter causes individuals to turn up the heating, and extreme heat in the summer increases the use of air conditioning. In the past, Ontario experienced peak loads during the winter, although summer and winter peak loads are now approximately equal. The peak record set in the summer of 2001 (25,269 MW on August 9) exceeded the old record set in January 1994 by 5%. Figure 2 depicts energy and peak power demand over time.

**Figure 2. Historical And Forecast Demand (Energy And Peak Power)<sup>1</sup>**



Forecasts assume normal weather and 1.1% annualized growth in energy demand, and 1.6% annualized growth in peak demand. Source: CIBC World Markets, IMO.

### System Supply

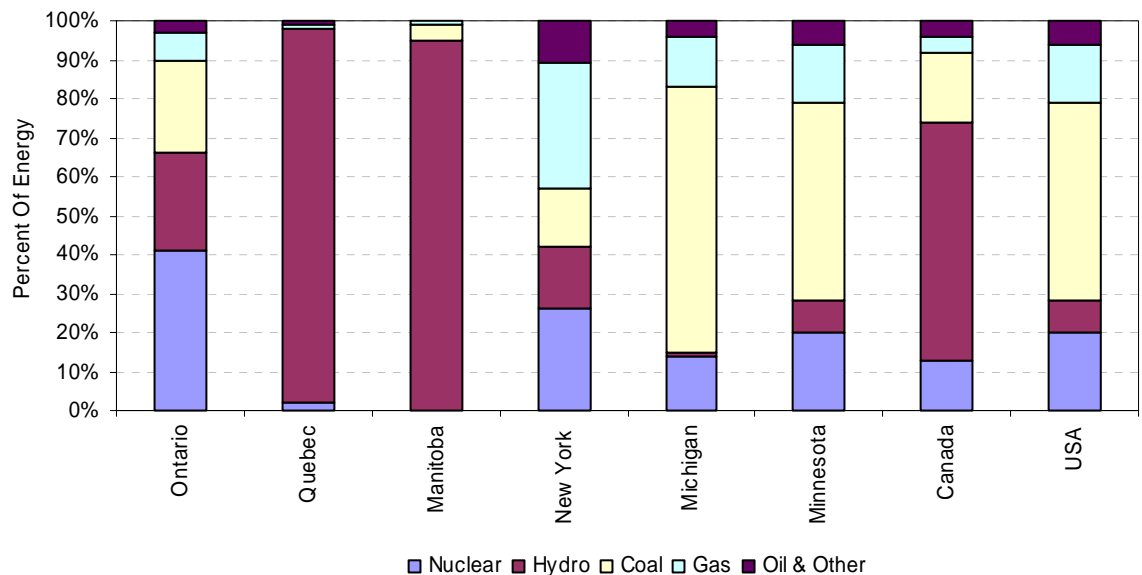
Adequate supply (in the form of generation and transmission capabilities) is considered to be the most important factor in creating and sustaining effective competitive electricity markets. Generation can be classified into three general categories — those that provide base, intermediate, and peak load capacities. Base load generation typically has a relatively high capital cost, which is offset by low marginal operating costs (typically below \$15/MWh); in Ontario, nuclear and some hydroelectric generating plants tend to be used to provide base loads. Peak load generation tends to have much lower capital costs, but relatively high marginal operating costs (up to \$150/MWh or more), and are generally deployed briefly during times of peak demand. Fossil plants, in particular natural gas-fuelled plants, and some hydroelectric plants that have reservoirs, can be used as peakers. Intermediate generation capacity falls in between the two extremes and both fossil and hydroelectric plants can act as intermediate generation, dependant upon the attributes of the individual plants. Table 7 breaks down the relative share of generation capacity in Ontario, and Figure 3 contrasts Ontario generation with that of the U.S.

**Table 7. Existing Ontario Generation**

Generation By Fuel	Capacity (MW)	Capacity Share (%)	# Stations	Size Range (MW)
Nuclear <sup>1</sup>	10,808	36.6 %	4	515 – 881
Coal	7,553	25.6	5	155 – 490
Oil/Gas	3,706	12.6	31	0.43 – 525
Hydro	7,419	25.1	127	0.04 – 136
Other (wind, waste, wood, etc.)	37	0.1	6	1 – 15
<b>Total</b>	<b>29,523</b>	<b>100.0</b>	<b>173</b>	<b>0.04 – 881</b>

<sup>1</sup> Does not include Bruce A nuclear units.  
Source: IMO.

**Figure 3. Ontario Generation Fuel Mix Compares Favourably To American Generation Fuel Mix**



Source: CIBC World Markets, Statistics Canada, OPG, EIA.

Companies perceive an opportunity for introducing more generation capacity into Ontario, as demonstrated in the current generation proposals submitted to the IMO and summarized in Table 8. All of the proposals listed are to be gas-fuelled.

Table 8. Proposed Ontario Generation

	Location	Size (MW)	Est. In Service	Status <sup>1</sup>
TransAlta – Sarnia	West	440	Q3/02	Completed SIA, Under Construction
Northland – Kirkland	Northeast	48	Q4/02	Completed SIA
AGSTAR Power <sup>1</sup>	West	88	Q1/03	Completed PA, SIA Not Active
Sithe – Brampton	Toronto	932	Q2/03	Completed SIA
Northland – Thorold	Niagara	273	Q3/03	Draft SIA
Sithe – Mississauga	West	763	Q1/04	Completed SIA
ATCO Power – Windsor	West	578	Q1/04	Completed SIA
AGSTAR Power <sup>2</sup>	West	538	Q1/04	Active PA
Calpine Canada	West	870	Q3/04	Completed PA, SIA Not Active
Imperial Oil	West	98	Q3/04	Completed PA, SIA Not Active
Ontario Power Generation	Toronto	550	Q4/04	Draft PA
<b>Total</b>		<b>5,228</b>		

<sup>1</sup> A preliminary assessment (PA) must be completed before a system impact assessment (SIA).

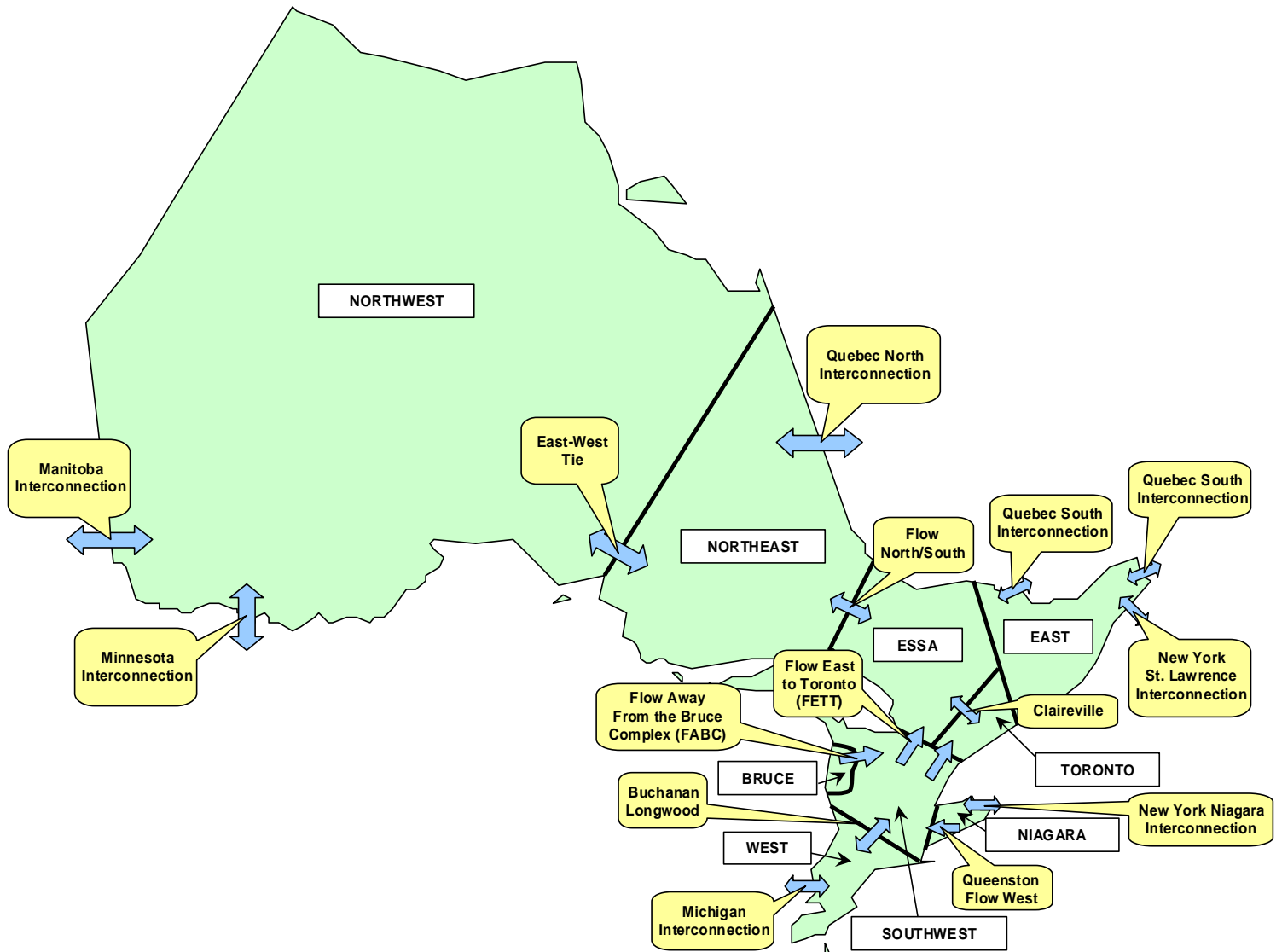
<sup>2</sup> TransAlta's number, that excludes behind-the-fence generation, used instead of IMO's 490 MW.

Enron proposal may be in doubt, given the company's recent difficulties. Original plans were to build 505 MW in the West zone by Q2/2004.

Source: IMO.

Ontario's transmission system provides vital infrastructure to deliver energy from where it is generated to where it is consumed. It can transfer power in bulk across interconnections within the province, and to other jurisdictions, but has both physical and system security limits. An effective transmission system allows loads to be served under a variety of generation, demand, and transmission conditions. When transmission is used to connect different electrical systems, it influences the economics of generation in that it 1) enables the economic exchange of energy among systems; 2) reduces the amount of installed generation capacity needed for reliability; and 3) limits the ability of generators to artificially raise prices due to the expansion of competition to a larger geographic region. Transmission is generally viewed as complementary to generation, but can be viewed as a substitute if access to remote generation eliminates the need for local generation. Conversely, generation located close to load centres can substitute for transmission. Figure 4 provides a map of major transmission zones within the province.

Figure 4. Map Of Provincial Intertie Zones

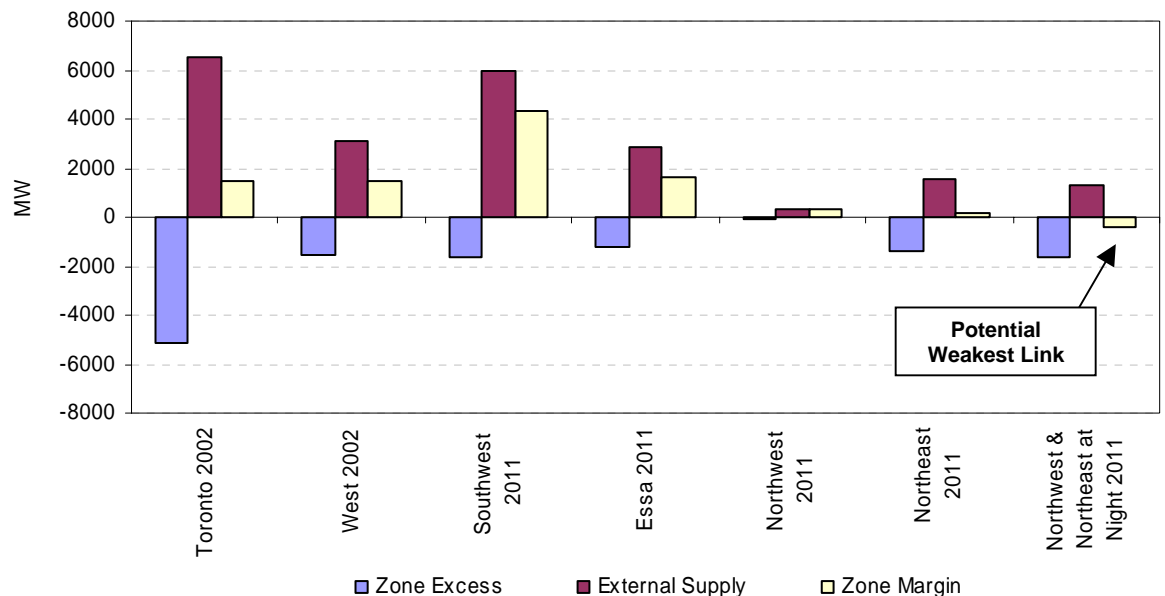


Zones depicted here are the zones incorporated into the IMO 10-year outlook, and future provincial reports will include revisions to these zones, such as the treatment of Ottawa as a unique zone separate from the East zone.  
 Source: IMO.

Within the province, Ontario’s transmission capabilities are forecast to be adequate over the next 10 years. The IMO forecasts that the Bruce, Niagara, and East transmission zones will have a local generation surplus requiring no transfers from adjacent zones even in an extreme weather scenario. Toronto’s local deficit in the event of extreme weather is projected to be highest in 2002, before all of the Pickering A units return to service. The West zone local supply is also tightest in 2002 before the four Windsor-Sarnia projects are complete; however, transmission capacity is sufficient over the next 10 years to bring in supply from adjacent zones if these projects do not materialize. Figure 5 summarizes margins for each zone for the worst-case time period in an extreme weather scenario.

The weakest link, however, becomes apparent only when the Northwest and Northeast zones are coupled in 2011, when the lack of 200-MW Manitoba Firm purchase creates a potential generation deficit that can not be entirely supplied from adjacent zones to the south, resulting in a potentially negative zone margin of 401 MW. The IMO suggests that reinforcement between the Essa/Toronto zones would alleviate the potential for a negative margin under extreme weather.

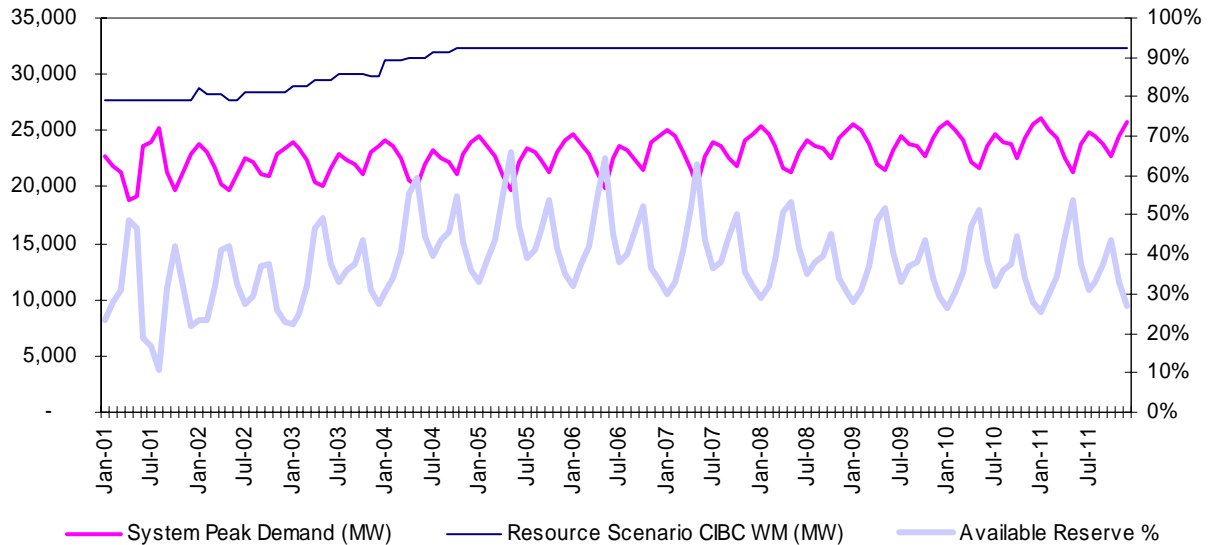
**Figure 5. Worst-Case Reliability For Zones With Local Deficits Under Extreme Weather Scenarios**



Zone excess is the local zone generation and demand balance, with two of the largest units in each zone out of service. (A negative zone excess implies a zone deficit.)  
 External supply is the lower of the interface transmission capability limit and the excess generation capacity at that time.  
 Zone margin is the difference between the external supply and the zone excess.  
 Source: IMO.

When mapped against peak demand (Figure 6) on a provincial level, our forecasts suggest that Ontario will enjoy more than adequate reserves (as required reserves are typically below 20%). Note that our supply forecast assumes that the first unit of Pickering A comes in service at the beginning of Q3/2002 and that the fourth and last unit comes in-service at the beginning of Q1/2004. This demonstrated adequacy of generation supply to meet demand going forward is a key success factor for Ontario. Now that the Ontario government has committed to deregulating energy sales, uncertainty of the regulatory climate has been reduced and the investment climate will likely be the determining factor for new generation in the future. This is in stark contrast to the experience in California in the 1980s and 1990s, when growth in power demand far outpaced virtually nonexistent growth in supply. Deregulation was a significant contributor to supply issues, in addition to stringent environmental regulations and the NIMBY (not-in-my-backyard) syndrome.

Figure 6. Available Reserves Appear Adequate To Meet Expected Demand



Supply based on existing generation capacity plus announced capacity additions risk-adjusted 50%.  
 Annual peak demand from previous demand scenarios.  
 Source: CIBC World Markets, IMO.

As a result of this ample generation capacity, we anticipate an increased opportunity to export excess power, which is discussed further in the subsequent section. Furthermore, higher reserve margins will minimize the cost of any minor shortcomings in the initial market design, as it will take time to improve upon, evolve, and optimize the markets.

### Ontario Market Not An Island Unto Itself

The bulk of generation in Ontario is consumed within the province, although currently a small fraction of Ontario’s electricity is exported to other markets. Some power is also imported, although as Table 9 illustrates, Ontario was a net exporter of electricity in 2000. Ontario is largely self-sufficient but at times can opportunistically take advantage of cheaper electricity to import in times of peak demand, and export surplus electricity if market prices in external markets provide opportunities for marginal profits. In times of excessive peak loads, external markets can also be looked upon to provide relief. The process for importing and exporting electricity is further discussed in the subsequent section on market balancing.

Table 9. Balance Of Energy Generated Versus Consumed In 2000 (TWh)

Energy In 2000 (TWh)	
Ontario Generation	154
Imported	4.5
Exported	(5.5)
System Losses	(10)
<b>Consumed In Ontario</b>	<b>143</b>

Source: OPG.

As noted in the previous section, we anticipate that the province will have increasing reserve margins, which creates the potential for growth of electricity exports. Peak export sales of 12.6 TWh were realized in 1994, but fell to a low of 3.0 TWh in 1998, with an average export volume of 4.8 TWh from 1996 to 2000. This decline was principally due to the lay-up of Bruce A and Pickering A nuclear generating facilities. Once new gas and laid-up nuclear generation capability comes online, we anticipate a discrete rise in export sales. At the same time, with an open and competitive market, imports are also likely to increase. Reliable and sufficient interconnections with external markets, summarized in Table 10, are key to enabling this trade.

**Table 10. Interconnections With External Markets (MW)**

	Flows Out Winter	Change During Summer	Flows In Winter	Change During Summer
Manitoba	300	(12)	369	(26)
Minnesota	150		100	
Quebec North	80		78	(14)
Quebec South	452	(20)	1,328	
New York Niagara	2,100		1,650	(250)
New York St. Lawrence	400		400	
Michigan	2,700	(250)	1,750	(100)
<b>Total<sup>1</sup></b>	<b>6,182</b>	<b>(282)</b>	<b>5,675</b>	<b>(390)</b>

Winter limits apply from November 1 to April 30, and summer limits apply from May 1 to October 31. Transmission capabilities decrease as the lines increase in temperature, and this accounts for the change in capabilities across the seasons.

<sup>1</sup> At best, the Ontario coincident import and export capabilities are around 3,900 MW and 5,800 MW, respectively — not the arithmetic sum. This is because the flows on the Michigan and New York Niagara interconnections can not be regulated, and this design limit constrains coincident flow.

Source: CIBC World Markets, IMO.

Ontario market participants must incorporate the incremental export fees of approximately \$5/MWh to \$6/MWh when calculating the total cost to deliver electricity into an interconnected market, and a breakdown of this export fee is provided in Table 11. Given that Manitoba and Quebec electricity is relatively cheaper than Ontario electricity (due to their disproportionate mix of hydroelectric power), we anticipate that the opportunities for exporting Ontario generation reside in the U.S. northeastern or midwestern markets, which tend to have relatively higher electricity costs due to the fuel mix of the generation (Figure 3).

**Table 11. Export Fee Breakdown**

Component Of Export Fee	Amount (\$/MWh)	Description
Export Transmission Service Rate	\$1.00	For usage of transmission network to export to points outside Ontario
IMO Administration Fee	1.00	For all market participants that withdraw energy from the IMO-controlled grid.
IMO Uplift	3.00 – 4.00	Provisions for system losses, operating reserve, capacity reserve, congestion management (internal to Ontario), black start capability, reactive support and voltage control, regulation service, must-run contract settlement, and outage cancellation/deferral. <sup>1</sup>
<b>Total</b>	<b>\$5.00 – \$6.00</b>	

<sup>1</sup> IMO estimates for each component vary widely.

Source: CIBC World Markets, IMO, OPG.

To facilitate energy flow with interconnected markets, Hydro One is obligated (according to the terms of its licence) to expend best efforts to expand intertie capacity with these markets by approximately 2,000 MW within 36 months of May 1, 2002 — day 1 of Open Access. Current plans include the installation of phase-shifting transformers on interties with Michigan that could increase intertie capability by up to 500 MW, and the increase of intertie capacity with Quebec by 1,250 MW. The Ontario–Michigan transformation installation is currently expected to be in service by October 2002, and the Ontario–Quebec in-service date is estimated to be Q2/2004.

The other major transmission project is a 975-MW high-voltage direct current (HVDC) merchant transmission line that would originate close to Nanticoke, Ontario, continue under Lake Erie, and terminate in either Ohio or Pennsylvania. This is a joint project between Hydro One and TransEnergie U.S., a subsidiary of Hydro-Quebec, and Q2/2004 is the planned in-service period.

## Markets Balance Loads With Sources

The OEB has authority to licence all market participants including the IMO, generators, transmitters, distributors, wholesalers and retailers. Rates to be charged for the distribution and transmission of electricity in the province will remain regulated for the foreseeable future and must be approved by the OEB. Any entity that receives authorization from the IMO can participate in the energy market in the capacity for which the entity is authorized, and 257 entities had applied to become participants as of January 3, 2002.<sup>5</sup> The wholesale competitive market structure in Ontario will consist of several markets that can be classified into three general groups as follows:

1. **Real-time markets**—pertain to actual delivery and use of electricity in Ontario, where the sale of energy and three types of operating reserves occur;
2. **Procurement markets**—pertain to ensuring reliability of Ontario’s power system (not real-time), where the sale of ancillary services occur; and
3. **Financial markets**—pertain to the transfer of money and risk (not delivery of electricity).

### Real-Time Markets

The real-time markets form the cornerstone of competitive electricity markets in Ontario, and they are where the competitive wholesale market price (or market-clearing price, MCP) is determined. Consumers and sellers in this market fall into two categories, dispatchable facilities and boundary entities. Dispatchable facilities are physical entities that can alter injection or withdrawal (of either supply or load) based on IMO instructions, and submit bids or offers that are input into the calculation of market prices which influence the actual dispatched power received by the IMO. Boundary entities are notional facilities that act much like dispatchable facilities, but import and export across interties with neighbouring jurisdictions.

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<sup>5</sup> There are seven classes of participants: 1) generators; 2) transmitters; 3) distributors; 4) wholesale consumers, who buy energy and services from the IMO-administered markets and from other market participants; 5) wholesale sellers, who sell energy and other services from the IMO-administered markets and to market participants; 6) retailers, who sell energy to consumers; and 7) financial market participants, who do not affect the physical flow of electricity.

The real time energy market is the market in which, conceptually every five minutes, supply offers for each hour of the day are stacked from lowest to highest price against demand, and the highest priced supply offer determines the MCP. Consumers whose bids exceed the MCP are dispatched on the grid, and sellers whose offer falls below the MCP will also be dispatched on the grid. The MCP will be exchanged by dispatched on entities independent of the original bids and offers.

The aforementioned process is for an ideal system that does not experience physical transmission limits. In reality, reliability constraints and the physical behaviour of the system can hinder the ideal dispatch, and the IMO must sometimes modify actual dispatch from the ideal calculated dispatch. When the actual dispatch differs from ideal, participants are additionally paid constrained on and off payments. For example, suppliers that are dispatched on, despite a higher-than-MCP offer, are paid the MCP plus a special “constrained on” payment, and the suppliers that are dispatched off, despite a lower-than-MCP offer, are paid a special “constrained off” payment only, which is the difference between their original offer and the MCP. Similarly, a consumer who bids above the MCP yet is not actually dispatched, receives a constrained-off payment as compensation.

The real-time operating reserve market enables the IMO to quickly respond to unexpected equipment failures or emergencies that disrupt the normal operations of the energy market. Both power sources and power loads can participate in the market, by offering to be on stand-by to either provide supply or reduce demand in case the IMO calls upon reserves. They submit both a reserve offer or bid and a corresponding energy offer or bid, which is used if the reserve is activated. Three separate reserve markets are managed to enable the IMO to draw on any of a 10-minute synchronized (spinning) reserve, 10-minute nonsynchronized (supplemental) reserve, or 30-minute nonsynchronized (replacement) reserve. Offers are stacked in each intertie zone in order of increasing price, and selected based on the IMO’s requirements, and in conjunction with the real-time energy market. All accepted reserve offers are paid the market price for standing by, regardless of whether or not the capacity is actually used. Unlike the energy-clearing price where one price is set for the province, the market price for each class of reserve varies across each of the intertie zones within the province. If an event occurs that requires the IMO to draw upon reserves, then the called-upon suppliers are paid the higher of their energy offer price or the MCP for energy prevailing for that period. Operating reserve payments cease for the duration that a facility is providing energy, as it no longer has the capacity to stand by.

Competitive markets for reserves, and other ancillary services, are important because most ancillary services are produced by the same generating units that produce energy. If the energy markets are competitive, but ancillary services remain regulated (as was the case initially in California), suppliers may recognize that they can earn more money selling energy than ancillary services and shift their output to energy production only, decreasing the reliability of the power system.

In addition to the real-time market, a market participant can enter into a physical bilateral contract to buy/sell a specified quantity of energy at a specified price. The terms of this contract do not get factored into the IMO’s dispatching decisions, and are used only in the settlement process (i.e., a contract for differences). If the contract is transparent to the IMO (i.e., the IMO is not advised of the time, amount, and point of supply for the energy), then the contract settlement occurs between the two parties in addition to the regular real-time energy market settlement process. If the parties submit contract data to the IMO, the IMO adjusts the two parties’ statements and participants settle using the contract prices.

### Procurement Market

Reliability of the power system requires ancillary services in addition to operating reserves that are arranged through a competitive tendering process. For example, frequency control, voltage control, reactive power, and black start capability (the ability of a generating unit to start up without relying upon the external electricity system) are contracted up to 18 months at a time.

Ancillary services, including operating reserves, provide a substantial opportunity for generating companies to maximize earnings. Variable costs for ancillary services tend to be lower than for energy sales, as there are often no fuel costs. The magnitude of incremental earnings garnered from ancillary services is dependent on the company's bidding strategy, the relationship between prices for energy and ancillary services, and the characteristics and costs of any given generating unit. For example, a large efficient base load generator may focus on selling energy, except on the few occasions when energy prices are below the unit's running costs and prices for ancillary services are relatively higher. Conversely, a high heat-rate, combustion-turbine peaker that can start quickly may sell largely ancillary services reserves. Academic research suggests that generator profitability can be increased by 10%–50% if a generator participates in ancillary services markets in addition to the energy market.<sup>6</sup>

### Financial Market

The transmission rights market is currently the sole financial market in Ontario, and pertains to transmission on interties between Ontario and other jurisdictions. This market enables participants to hedge exposure to price spreads across jurisdictions in the event that an intertie reaches capacity. The rights are financial only and do not give the holder scheduling priority. In the future, we anticipate that an energy forwards and/or futures market will be introduced as the competitive markets mature. A standardized market for longer-term instruments should facilitate liquidity, although it is still unclear whether the IMO, or a private company, is best equipped to operate such an exchange.

### Ontario Wholesale Electricity Market Is A Flexible, Learning Entity

The delay in market opening has enabled the IMO to leverage the experiences of deregulation in other jurisdictions, however even these markets are still evolving. Unique attributes within each system require the IMO to further build up analytic and administrative capabilities under a live, deregulated market before more sophisticated elements (e.g., congestion pricing) can be effectively introduced. It is widely recognized that the initial market design will not be static, but a dynamic process that will evolve over time. The IMO has identified the following high priority issues that will influence the evolution of the Ontario electricity market:

1. **The Energy Forward Market (EFM)**, a voluntary, day-ahead, financial, hourly bid market, has been deferred indefinitely until there is further clarity as to participant demand for the EFM. Current indications suggest participants see more value in longer-term (monthly or quarterly) hedging instruments, and the IMO is open to considering all options, including the creation of a full-fledged futures exchange.

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<sup>6</sup> Hirst, Eric, *Maximizing Generator Profits Across Energy and Ancillary-Services Markets*, March 2000.

2. **The Capacity Reserve Market (CRM)**, a semi-annual auction where generators offer capacity for availability as operating reserves, has been deferred for 12 months and uncertainty remains as to its relevance. There is considerable debate around the adequacy of energy prices alone to signal the need for capacity additions, and linkage with external jurisdictions remains an issue.
3. **Locational Marginal Pricing (LMP)** (charging different rates for transmission based on location and network congestion) would refine market signals to provide incentives for the optimal location of loads, generation, and transmission appropriately within the province. Current market design allocates congestion costs to all market participants, and is managed through the constrained on and off payments discussed previously. This would expand transmission rights financial instruments beyond interties with other jurisdictions to interconnections within the province and would heighten the importance of support for secondary markets in these instruments.
4. **International trade** of operating reserve and other “seams” issues with the U.S. are being worked on, and these efforts have recently changed in scope due to the Federal Energy Regulatory Commission’s (FERC’s) mandate to develop a single Regional Transmission Organisation (RTO) in the Northeast.
5. **True real-time bidding** is not provided for in the initial market design. Instead, initial bids and offers must be submitted at least four hours in advance, with a provision for changes within 10% of original value allowed up to two hours in advance. Other changes up to real time require special consent of the IMO. It is unclear to what extent shorter timeframes are beneficial for participants (in contrast to some lead-time for scheduling).
6. **Transmission Expansion** requirements will be identified in the IMO’s annual 10-year system adequacy projections. This will encourage participants to supply options and proposals for resolving potential constraints. Transmitters will be requested to supply enhancements to the system, although the role of merchant transmission lines in this process remains uncertain. Participants are still able to submit proposals to invest in facilities not specifically identified in the IMO’s annual process.

### Retail Market

Retail customers and small commercial customers must continue to be supplied by the distributor under SSS unless the customer chooses to purchase electricity from a licensed retailer. Price agreements range in duration from spot market prices (under SSS) to five-year fixed or variable prices (retailer). In the first year, the SSS energy price will be an estimate of the year one average spot market price, and any deficit or surplus will be factored into the price paid in year two. Approximately 40% of the retail customer’s total bill will remain regulated, and the retailers will be competing on the energy charge only, approximately 60% of a typical retail price. A complete breakdown of a typical retail total electricity price is described in Table 12. Retailers may choose to compete with incentives, such as Air Miles, in addition to price. Customers may perceive value in the ability to lock in prices over a longer time, as this reduces uncertainty. Some other jurisdictions have also added choice as to which kind of generation source, specifically “green power”, to purchase and customers may value this additional choice as well; however, many retailers will require customers to sign over OPG rebates, and this could offset any such additional incentives.

The OPG rebate is a result of the market power mitigation requirement that caps OPG's revenue from a large portion of its energy sales at 3.8 cents per kWh and cushions the impact of price spikes for retail consumers. The price OPG will receive in the open market could be greater than 3.8 cents, and if this occurs then electricity consumers will receive a rebate from OPG on a percentage of that amount. The percentage received will be based on the percentage of generation that OPG supplies to Ontario residents. Non-OPG generation purchased will be at the market prices. In 2000, OPG enjoyed an 89% market share, although this will decline over time. An unknown variable in the rebate, which will remain unknown until one year after market opening, is the amount that OPG's average revenue exceeded 3.8 cents per kWh. The rebate will be paid after the first year of deregulation to consumers and businesses that have not assigned it to someone else. The rebate is effective for the first four years of deregulation, but at a declining rate as OPG sells off more generating assets.

**Table 12. Illustrative Electricity Price For Retail Consumer**

<b>Retail Price Component</b>	<b>Charge (cents per kWh)</b>	<b>Share Of Total (%)</b>	<b>Description Of Charge</b>
Energy Charge (Commodity)	5.95	60%	Cost of electricity generation, component open to competition. <sup>1</sup>
Distribution Charge	1.00	10	Construction and maintenance of distribution system.
Transmission Charge	1.00	10	Transmission of electricity from source to distribution system.
Customer Charge	0.72	7	Fixed monthly cost of having an account and basic service from the utility. <sup>2</sup>
Debt Retirement Charge	0.70	7	Contribution to payment of stranded debt of former Ontario Hydro.
System Operation And Regulation	0.50	5	Market regulation and IMO oversight of system.
<b>Total</b>	<b>9.87</b>	<b>100%</b>	<b>Total Price To Consumer<sup>3</sup></b>

<sup>1</sup> Prices offered on January 3, 2002 for a five-year fixed contract in Toronto.

<sup>2</sup> A typical customer charge is a fixed monthly charge of approximately \$9, and a typical Ontario household with oil or gas space heat uses about 15,000 kWh per year.

<sup>3</sup> A typical fully regulated retail electricity price for urban retail customers, effective October 1, 2001, is 9.46 cents per kWh. This is based on a variable charge of 8.585 cents per kWh and assumes the \$10.90 monthly service charge is allocated over 15,000 kWh in the month.

Source: CIBC World Markets, Energy Shop, Hydro One.

Retailers must educate consumers about the merits of switching from SSS, then convert and retain customers to their own offering. As retailers will be competing primarily on price, whether overtly or in the guise of incentives, and secondarily on service, we anticipate that managing operating costs and seeking operational excellence will be a key success factor in securing competitive advantage. Incentives offered by a given retailer must be sufficient to first of all overcome inertia of a customer to remain on SSS, and secondly cause the consumer to choose an individual retailer over other retailers. We note with great interest the rush of retailers signing up customers as they seek first-mover advantage in converting customers. As of mid-December, 54 electricity retailers were licensed in Ontario and 23 applications for licences were pending.

The cost of electricity sold will be a large component of a retailer's costs. We anticipate that a retailer will likely be able to source electricity at an increasingly lower price as the volume of energy purchased increases. We also note the large economies of scale in employing hedging strategies, whether natural or synthetic, further indication that size matters in this arena. Furthermore, fixed costs of operations such as customer call centres and other administrative and general costs become less of a burden if they are spread across higher volumes of sales.

Economies of scope can also be leveraged for competitive advantage in retail commodity distribution. For example, customer acquisition costs can be significant in many retail environments, and many retailers seek to cross-sell and up-sell products to customers to maximize revenues per customer. We believe that there could be substantial synergies in selling multiple commodities to a given customer. Natural gas is a likely candidate to be offered to an electricity customer, but there also exists an opportunity to explore the cross-selling of other services such as home security or monitoring. Up-selling could be achieved by providing value-added services such as energy conservation consulting. Although we acknowledge that some niches may exist, we anticipate that most survivors will be big. This is a contributing factor to our view that there will be further consolidation of the MEUs. Table 13 highlights some of the potentially larger competitive retailer candidates, although this list is by no means exhaustive or true for the longer term.

**Table 13. Initial Short-List Of Larger Competitive Energy Offering Players**

<b>Company</b>	<b>Est. Number Of Customers</b>	<b>Status In Electricity Offering</b>
Direct Energy	1 million +	Estimated 200k signed up
Energy Savings	300k +	Hasn't launched yet
Enbridge Home Services	70k	Hasn't launched yet
Sunoco	50k	Hasn't launched yet
EPCOR (Union Energy) <sup>1</sup>	900k +	Hasn't launched yet
Ontario Hydro Energy's Onsource	TBD	Launched

<sup>1</sup> Union Energy's primary business is the rental of water heaters, but in conjunction with Westcoast Capital, it also provides heating, ventilation and air conditioning products and servicing, financing, and retail sales of natural gas.  
Source: CIBC World Markets.

The next largest components of a typical customer's bill, after the commodity charge, are the distribution and transmission charges. While the distribution and transmission elements of Ontario will continue to be regulated, we believe that these costs could be reduced over time (after initial upward adjustments to distribution notes) with the introduction of PBR regimes. As discussed earlier, we believe that the eventual introduction of incentive regimes for distribution and transmission will reduce inefficiencies and benefit both customers as well as companies.

### **Commercial Market**

As the size of a commercial customer increases, so too does its purchasing power and options. Smaller customers may choose the SSS option, the retailer purchase option, or the option to join a buying group to aggregate volume for increased purchasing power. Larger commercial customers with a load in excess of 50 kW and an interval meter can register to become a wholesale market participant.

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## Popular Misconceptions

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The announcement that the Ontario Government will privatize Hydro One through an initial public offering was well covered by both local and national media. Many reports cited concerns about the possible negative implications of such a move. In our view, many of these fears are unfounded and reflect an improper understanding of the restructuring of the Ontario electricity market and how the privatization relates to that restructuring. While an important compliment to the restructuring that should produce additional benefits, it is the restructuring itself that is the major driver of change. Below we discuss some of what we believe are popular misconceptions surrounding restructuring and privatization.

### **Myth #1: Privatization Will Cause Rates To Rise**

One widely quoted opinion was that the electricity rates will rise by 20% following privatization. Purportedly, this will be the result of the presence of additional “profit-takers” in the system. In evaluating this concern, it is important to distinguish between privatization and deregulation. As described earlier in this report, a central feature of the restructuring of the Ontario electricity industry involves deregulation of the generation and sale of electricity. The delivery of electricity — the business of Hydro One — will remain regulated regardless of whether or not Hydro One is owned by the Province or individual shareholders. Transmission and distribution rates will continue to be set by the OEB and the company will be able to charge only those rates that are approved by the OEB.

Furthermore, it is important to note that profits and income taxes are already built into Hydro One’s rates. When Hydro One was created from the old Ontario Hydro, it was created with a commercial capital structure. Its revenue requirement is set by the OEB on the assumption that 40% of Hydro One’s capital structure consists of common equity and, currently, are designed to produce an after tax return on that equity of 9.88%.<sup>7</sup> As a crown corporation, Hydro One would normally be exempt from income tax; however, the Electricity Act provides that Hydro One (along with OPG and the MEUs) must make payments to the provincial government in lieu of provincial and federal income tax that would be payable by an investor-owned utility.

As a result, we see no upward pressure on Hydro One’s distribution rates as a result of privatization. Indeed, it is conceivable that, in time, rates could actually be lower than they would be if Hydro One were to remain a crown corporation. That said, the Minister of Finance has the discretion to increase the debt-reduction charge independent of the ownership structure of Hydro One, which could offset any eventual decline in rates. As an investor-owned corporation, management and employees may have the opportunity to receive stock options or other forms of incentive compensation. As a result, they will be motivated to make the corporation more efficient and profitable. This is possible with PBR, which is already being used by the OEB with respect to the company’s distribution rates and which will likely be introduced for transmission rates in 2004. With PBR, the benefits of costs-savings and innovation are typically shared between shareholders and customers.

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<sup>7</sup> As a result of the previous rate freeze, and to avoid an undue one-time rate increase required to generate Hydro One’s full revenue requirement, Hydro One has proposed a three-stage rate increase, the first of which was implemented on October 1, 2001.

**Myth #2: Deregulation Caused Prices To Soar In California**

California and to a lesser extent Alberta have been cited as examples of the negative results of deregulation. In California, wholesale electricity prices soared, there were rolling blackouts, and a major utility filed for bankruptcy protection. Another came close. As described in our January 31, 2001, report on electricity deregulation, however, this was not the result of deregulation per se. Rather it was the result of flawed deregulation undertaken at a time when there were serious transmission constraints, a shortage of adequate in-state generation, and a high reliance on gas-fired generation at a time when gas prices were skyrocketing.

Despite years of strong economic growth with an attendant growth in demand for electricity, no material amount of new generation was built in California. Stringent environmental regulations with respect to NO<sub>x</sub> in Southern California and the NIMBY syndrome brought new plant construction virtually to a halt. While California's demand grew by about 3,000 MW between 1996 and 2000, generating capacity increased by only 500 MW. Companies were unwilling to invest in an uncertain regulatory and financial climate. Higher generation costs in the form of NO<sub>x</sub> cost allowances and natural gas prices increased power costs. Lack of investment in transmission capabilities exacerbated the lack of new generation, as the state's transmission capabilities as measured in MW-miles fell relative to peak summer demand in the 1990s. For example, California's north-south transmission corridor in the middle of the state was notoriously congested and caused electricity consumers to experience considerable congestion costs.

Supply became further squeezed when dry weather constrained output of hydroelectric dams in California and the Pacific Northwest, and high growth in demand elsewhere in the western U.S. limited imports. Generation owners began to withhold supplies from the California markets because they were worried about the financial status of the California utilities, which further worsened the supply-demand imbalance and led to several emergencies, including rotating blackouts in January and May 2001.

Deregulating at a time of growing demand and constrained supply was a recipe for rising electricity prices, but California's approach to deregulation exacerbated the situation. California introduced electricity deregulation with the passage of Bill AB 1890, in September 1996. In order to mitigate the market power that could be exerted by the state's utilities in a competitive market, the utilities were forced to sell significant portions of their fossil-based generating capacity, without simultaneously hedging their power supply through long-term contracts.

As growing demand collided with constrained supply, the utilities were destined to pay more for power; however, the situation was severely aggravated by requiring the utilities to buy on the spot market all the power they could not generate themselves. During the period while they were recovering stranded costs, they were not permitted to enter into long-term power supply contracts. The utilities were forced to buy much of their requirements from competitive generators — either within or beyond the state's borders — based on the price of power in a competitive market established by the high-marginal-operating-cost fossil units.

At the same time as the utilities were being forced to buy much of their power requirements in a rising and volatile spot market, the rates they could charge their retail customers remained frozen at a 10% discount to 1996 levels. It was this combination of a deregulated wholesale market and fixed-price retail market that pushed the state's two largest utilities to the edge of bankruptcy, as they were unable to fully recover their power costs. As well, immunity from real economic prices meant that customers had no incentive to curtail demand when an especially hot summer and cold winter caused higher-than-anticipated demand for space cooling and heating.

Furthermore, with this background, it is easier to see why we do not anticipate a California-style crisis in Ontario. As discussed earlier, we anticipate an adequate supply of in-province generation. Also, participants are able to enter into long-term contracts to manage risks and hedge exposure to energy prices as they see fit. We anticipate the development of standardized forwards and/or futures markets to provide liquidity. As well, and unlike California, retail prices will not be decoupled from wholesale prices. Ontario customers receiving standard supply option will pay average market prices. As a result, the essential link between price and demand that is necessary to a properly functioning competitive market will not be severed.

Also unlike California, Ontario's internal and external transmission systems are expected to be adequate to ensure system balance in each region, in contrast to California's constraints.

In Alberta as well, there was an initial spike in prices. Here again, however, it was not deregulation per se that was the cause, but rather the extended period of transition to deregulation during which the final rules were not clear. In the face of uncertainty, investors were reluctant to commit funds to build new generation. With tight supply and a buoyant economy, prices were bound to rise. Already, however, prices have retreated as new generation, attracted by high prices, has entered the market.

Rather than focus solely on the mistakes in California and the bumpy transition in Alberta, we believe that it is instructive to look at the successes of other jurisdictions. For example, customers have benefited from reduced prices in other jurisdictions — in Pennsylvania the rates fell 3% in one year, saving customers US\$3 billion. Abroad, U.K. prices fell 10%–15% and prices in Australia fell 24%. Pennsylvania also experienced a strong increase in the number of competitors; by April 2001, 600,000 customers had switched providers, and 130 supply companies were vying for their business. The response to increased customer choice has been positive in Pennsylvania as well — 20% of the aforementioned customers who switched chose a more expensive “green” power option. This decrease in prices and increased choice caused customers in Pennsylvania to be on average nearly 25% more satisfied with their electricity service than the national average.<sup>8</sup>

### **Myth #3: Deregulation Will Cause Ontario Electricity Prices To Rise**

Some have expressed a concern that with the introduction of competition and the opening of Ontario's transmission and distribution networks, Ontario generators will seek to sell their power to higher-priced U.S. markets, which will cause Ontario rates to rise to levels seen in adjacent U.S. markets. It is true that in a competitive environment, market forces will set prices and, as a result, it is impossible to predict with precision, what commodity prices will be; however, we note the following factors that will diminish, if not eliminate, any upward pressure on customers' bills. We offer the following data points to debunk this myth:

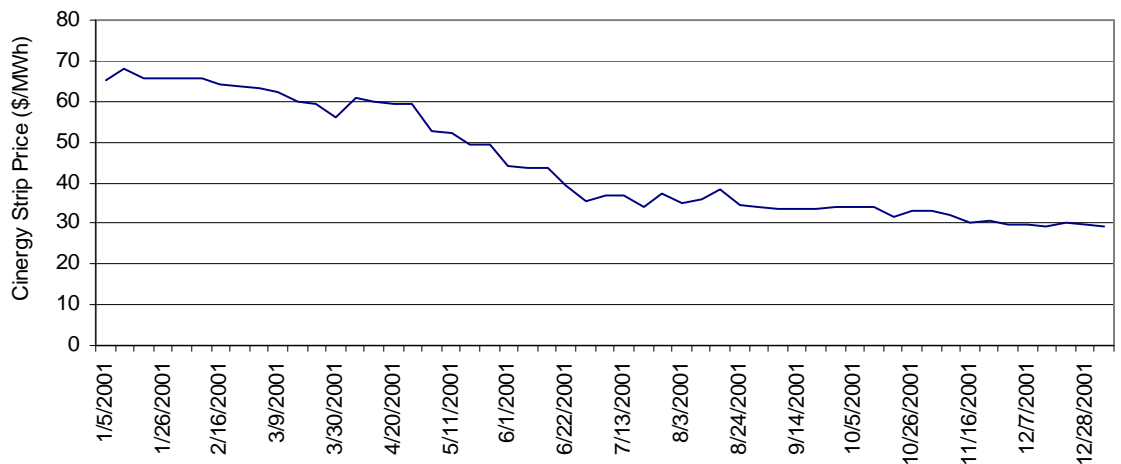
1. For residential customers, the cost of electricity constitutes only about 60% of the total bill. The other components (transmission and distribution wires charges, customer charge and stranded debt recovery) will remain regulated.
2. While adjusted for exchange rates, U.S. prices in the Midwest and Northeast regions are higher than current Ontario rates, the cost of moving electricity (approximately \$5/MWh to \$6/MWh plus associated transmission costs in the U.S.) from Ontario to those markets will reduce the incentive to do so.

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<sup>8</sup> Statistics from this paragraph extracted from policy study paper by Lynne Kiesling, entitled *Getting Electricity Deregulation Right*, published April 2001.

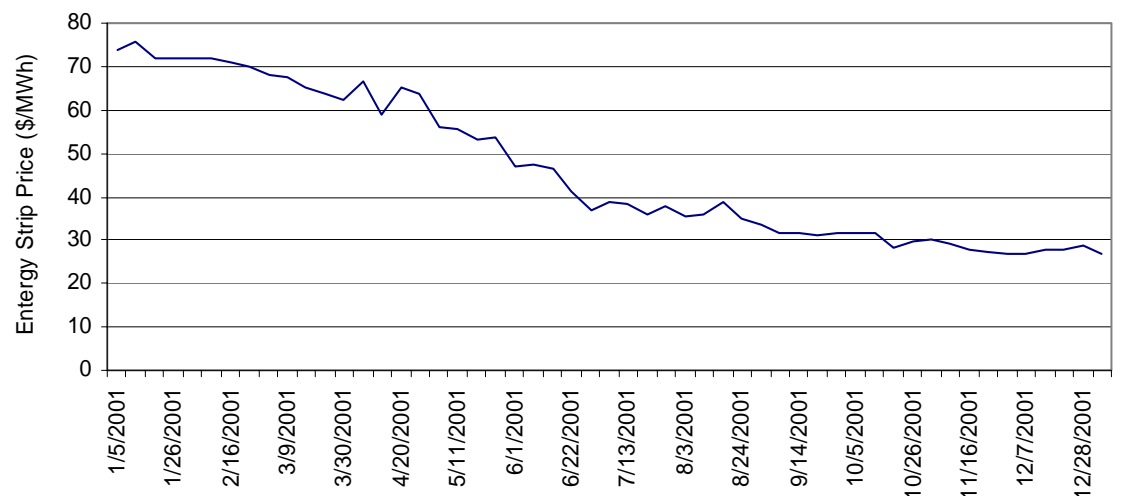
3. Power prices in the U.S. have moderated. The recent 12-month strips for the Cinergy and Entergy hubs were US\$29.27/MWh and US\$26.68/MWh, respectively. As shown in figures 7 and 8, this has trended down considerably compared to year-ago pricing of US\$64.94/MWh and US\$73.96/MWh. Given the current chatter about potentially excess generation capacity in the U.S., prices could stay lower for a while.
4. While markets to the south of Ontario have traditionally been higher priced, those to the east (Quebec) and west (Manitoba) have traditionally been lower priced, which should provide an opportunity for Ontario buyers to import cheaper electricity.
5. For the first four years following the introduction of open access on May 1, 2002, OPG will face an average annual cap on the bulk of its domestic sales of \$38/MWh.
6. With a properly functioning competitive market, rising prices will be an inducement to generators to add more capacity, which will in turn have a moderating impact on prices. If too much capacity is added, the generators' shareholders will pay the price rather than customers as was the case in the era when generation was owned by a government-owned monopoly. The high cost of Ontario's Darlington nuclear generating station is a classic case in point.

**Figure 7. Cinergy Strip Prices Have Declined Over Time**



Source: CIBC World Markets, Bloomberg.

**Figure 8. Entergy Strip Prices Have Declined Over Time**



Source: CIBC World Markets, Bloomberg.

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## Conclusion: The Future Is Bright

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### Market Well-Designed

Deregulation and the privatization of Hydro One facilitate the beginning of a robust, commercial electricity market. The decision to deregulate was not a slam-dunk for the government — many factors had to be weighed to ensure that the needs of all stakeholders were considered and addressed. We believe that the province has struck a prudent balance between managing the complexities of this endeavour and striving to make a timely decision.

Our research leads us to believe that the Ontario electricity market has all the key ingredients for a smoothly functioning market — especially adequate supply and a robust market design. Customers and suppliers are provided with the opportunity to protect themselves from price volatility; regulated entities are provided with incentives to reduce costs; and retailers are provided the flexibility to provide somewhat differentiated product and service offerings. Market prices provide price signals to support efficient decision-making by all parties.

### Room For Both Incumbents And Entrants To Play

Open Access, slated for May 1, 2002, sets the stage for sweeping change in the Ontario electricity market, and opportunities abound for established incumbents and entrants alike.

Companies are jockeying to establish a generation presence to meet the needs of both the Ontario and adjacent markets. Independent and merchant power producers will enter the markets by either acquiring units slated for decontrol from OPG or by building units in greenfield projects. **TransAlta** will be able to sell surplus power from its plants in Sarnia and Windsor — either to domestic markets or to markets in the northeastern and midwestern U.S. We anticipate that TransAlta will increase its presence in Ontario over time, and its portfolio of generation may eventually encompass base, intermediate, and peak load units.

**TransCanada PipeLines** has indicated that it has, and will continue to have, a strong interest in Ontario and that it is actively seeking to increase its generation presence in the province. That said, the company has indicated that it is not likely to be a buyer of the current assets up for sale; instead, it would be more interested in the next round of base load units. In the mean time, the company will continue to pursue opportunities for enhanced combined-cycle units, ranging in size from 40 MW to 100 MW, in conjunction with compressor stations on its mainline. It is also looking to market contracted supply to industrial customers in Ontario — in the same fashion as its Alberta marketing unit.

**ATCO Power** (a subsidiary of **Canadian Utilities**) has a demonstrated capability in developing greenfield projects and we note that its proposed gas-fuelled plant in Windsor is well positioned for export into the U.S. American companies have scaled back expansion plans, and we anticipate that their presence in the Ontario market may not be felt for some years. Once the hangover that the U.S. energy sector is experiencing from Enron's demise dissipates, and as these companies' access to capital for expansion returns, we believe that Ontario will be an attractive market for them.

Not all companies are racing to enter Ontario. **Emera** expended considerable effort in establishing a presence in Ontario a few years ago to no avail, and has since redeployed its resources to growing in the U.S. Northeast. We believe that the company would consider opportunistically purchasing a company or assets if something presented itself, although this is not very likely to occur in the near term.

**Fortis** first entered the Ontario market in 1996 through the purchase of a 50% interest in Canadian Niagara Power. It was frustrated by the transfer tax in its initial efforts to use Canadian Niagara as a beachhead from which to participate in the consolidation of smaller municipal distributors. Nonetheless, Fortis is a long-term player and remains interested in the Ontario market. We would expect the company to play to its strengths. These include its experience in the area of small-scale hydroelectric development. As well, with its relatively small size, Fortis could look at municipal distribution opportunities that might be too small to interest larger players. Fortis has demonstrated creativity in working around the punitive transfer tax. In 2001, a subsidiary of the company signed a 10-year lease with the City of Port Colborne for the use of the city's distribution operations. The subsidiary receives the revenue streams, pays all operating and capital costs, owns all capital additions, and holds an option to purchase the business for fair market value at the end of the 10-year term. We believe that Fortis, and perhaps other players, could enter into similar agreements with other cities and towns. We don't anticipate Fortis considering competitive retail, however, as it is outside the scope of its core competencies.

Within the province, **Ontario Power Generation's** opportunities reside in focusing on realizing the full potential of its existing generating units not slated for decontrol. We believe that accelerating decontrol should be a top priority, as it is in the company's best interest to minimize the impact of the rate cap. Controlling costs will require the successful and cost-efficient return to service of Pickering A; moreover, continued improvement of the company's entire nuclear units to levels that meet or exceed international benchmarks is a key success factor.

As **Hydro One** is the dominant transmission operator and largest distributor in Ontario, we see opportunities for it. These include the potential to increase its profitability with performance based regulation in its distribution business and, in time, its transmission business as well. With its size and scope, Hydro One is in an excellent position to continue its consolidation of municipal distribution systems. Its experience and expertise also position it to participate in and benefit from the consolidation and investment opportunities that are expected to arise in the U.S. We would also expect further transmission opportunities within the province — either regulated or merchant, given Ontario's position between two lower-priced Canadian markets and higher-priced U.S. markets. We see the planned privatization of Hydro One as positive in that it will give it access to capital to exploit these opportunities. The discipline of the market will also provide feedback to management as it executes on its growth strategy.

The retail energy markets are conceptually compelling, but retailers must first overcome consumer apathy and inertia to convincingly educate consumers about the merits of switching from SSS, then convert and retain customers to their own offering; however, for any retailer to succeed, scale economies will be key to capturing the value that they create for customers. **Enbridge Energy Services** will be able to realize economies of scope as it markets both electricity and gas to the province's customers. Longer term, as the impact of the transfer tax dissipates, we see opportunities for Enbridge Consumers Gas to start acquiring MEUs and profiting from the PBR framework through economies of scope across both gas and electricity distribution.

As the impact of the transfer tax dissipates on MEU acquisitions over the next decade, distribution companies will find consolidation more economically compelling, and this will fuel consolidation of distribution utilities through either 1) entrants into the industry, such as Enbridge, or 2) M&A activity among the MEUs themselves. With the introduction of second-generation PBR and sharing of overearnings, distribution companies, and customers alike will benefit from the efficiencies gained from consolidation.

OPG and Hydro One will likely grow beyond the borders of Ontario and export their expertise in generation, transmission, and distribution across North America. Of course, such expansion must not distract the companies from improving operations in their home market. Given that many American power generation companies have scaled back growth prospects, we anticipate substantial opportunity for home-grown talent to shine in the near term.

In summary, we expect that the incumbents will continue to leverage their economies of scale and strong presence in Ontario, and seek prudent growth outside the province. Managing costs and developing a competitive mindset at all levels of their organizations will be key challenges for the companies.

Entrants into Ontario will likely be opportunistic as they seek footholds that will enable them to leverage their unique strengths. While lacking a large local presence initially, they can use this to their advantage by nimbly responding to market dynamics. Over time, the lines will blur between the incumbents and the entrants, and the markets will mature into a vibrant commerce hub. The future of the Ontario electricity industry, and the companies that can create and capture value in the market, is certainly bright.

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